Canadian Natural

Annual Report 2003

General information

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Company definition

Throughout the annual report, Canadian Natural Resources Limited is referred to as "Canadian Natural" or the "Company".

Currency

All amounts are reported in Canadian currency unless otherwise stated.

Abbreviations

AIF	Annual Information Form
bbl	barrel
bbl/d	barrels per day
bcf	billion cubic feet
bcf/d	billion cubic feet per day
bcfe	billion cubic feet equivalent
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian dollars
CDOR	Canadian Deposit Overnight Rate
EOR	Enhanced oil recovery
E&P	Exploration and production
FPSO	Floating, Production, Storage and Offtake Vessel
Horizon Project	Horizon Oil Sands Project
LIBOR	London Interbank Offered Rate
mbbl	thousand barrels
mbbl/d	thousand barrels per day
mboe	thousand barrels of oil equivalent
mboe/d	thousand barrels of oil equivalent per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mcfe/d	thousand cubic feet equivalent per day
mmbbl	million barrels
mmbbl/d	million barrels per day
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mmcf/d	million cubic feet per day
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
Petrovera	Petrovera Partnership
Rio Alto	Rio Alto Exploration Ltd.
SCO	synthetic light crude oil
SO2	sulphur dioxide
tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US$	United States dollars
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate

Cautionary statements

Certain information regarding the Company contained herein may constitute forward-looking statements under applicable securities laws. Such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated or implied in the forward-looking statements. Please refer to page 39 for complete special note on forward-looking statements.

All production, sales and reserve statistics represent Canadian Natural's working interest amounts before deduction of royalties unless stated otherwise. Where volumes are reported in barrels of oil equivalent ("boe"), natural gas is converted to oil at six thousand cubic feet per barrel unless otherwise noted. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head. Methodologies for determining annual reserves are described on pages 14 to 17.

This report also includes references to financial measures commonly used in the oil and gas industry which are not defined by Generally Accepted Accounting Principles. The Company uses these measures to evaluate the performance of its business segments, however they should not be considered an alternative to or more meaningful than net earnings.

Common share dividend

In January 2001, the Board of Directors approved the payment of a regular quarterly dividend of C$0.10 per common share commencing April 2001, which was subsequently increased to C$0.125 per common share effective April 2002 and to C$0.15 per common share effective April 2003.

In February 2004, the Company announced an increase in the quarterly dividend to C$0.20 per common share from C$0.15 per common share annually, a 33 percent increase in the dividend rate, which recognizes the strength of Canadian Natural's cash flow and provides an increased return to our shareholders. This marks the fourth year of dividend distributions by Canadian Natural and the third consecutive year the distribution has been increased.

Notice of annual meeting

Canadian Natural's Annual and Special Meeting of the Shareholders will be held on Thursday, May 6, 2004 at 3:00 p.m. Mountain Daylight Time in Macleod Hall A, of the Telus Convention Centre, Calgary, Alberta. All shareholders are invited to attend.

Metric conversion chart

To convert	To	Multiply by
barrels	cubic meters	0.159
thousand cubic feet	cubic meters	28.174
feet	meters	0.305
miles	kilometers	1.609
acres	hectares	0.405
tonnes	tons	1.102

Our mission statement

To develop people to work together to create value for the Company's shareholders by doing it right with fun and integrity.

We projected...

Production

Our actual production came within guidance parameters established at the beginning of the year. Natural gas production increased by 5 percent while crude oil and NGLs production increased 13 percent.

Cash flow and earnings

Higher than anticipated commodity prices resulted in significantly higher cash flow and earnings, which the Company utilized to opportunistically reduce debt, increase capital spending and buy back shares.

Drilling

Natural gas and heavy oil drilling were ramped up over budgeted levels in order to take further advantage of robust product pricing. This helped to set up continued aggressive drilling programs for 2004.

Future planning

Five year development plans for each product and basin were better articulated, allowing our Shareholders to better understand our core competencies and competitive advantages. This process also helps Company Management to direct resources in an appropriate manner to facilitate delivery of the programs.

We delivered.

Natural gas

- Rio Alto properties were fully integrated, facilitating cost reductions and exploitation program development.
- The Cardium development team completed its regional geological modelling study enabling the Company to better determine the best drilling locations. At the same time, the team also determined best practices for drilling, allowing significant reductions in capital costs.
- A new regional shallow gas target, the Notikewin, was identified with development initiated during the 2003/4 drilling season.
- 777 wells were drilled compared with the original budget of 500-600 wells.
- Entry to exit production growth of approximately 3 percent, or 32 mmcf/d exclusive of Ladyfern production.
- Acquired additional natural gas plant facilities in Northeast British Columbia, facilitating cost savings and additional access to processing facilities required to further grow production.

North American oil and NGLs

- The three-pronged heavy oil marketing strategy was articulated with the Synbit strategy being identified and implemented.
- The Primrose thermal oil expansion plan was approved with 41 wells having been drilled with first production expected in mid-2004.
- The Pelican Lake enhanced oil recovery plan entered a new phase with a plan to implement waterflood throughout the field. Emulsion floods will be utilized to further enhance success of this program.
- 446 wells were drilled, compared with an original budget of approximately 400 wells.
- Entry to exit production growth of 9 mbbl/d or 6 percent.

North Sea

- The Company completed further acquisitions and now operates 99 percent of its production with average working interests of approximately 80 percent.
- Assumed operatorship of three Northern North Sea platforms and implemented exploitation programs. Waterflood optimization, maintenance programs and drilling programs extended useful life of these assets by several years.
- Reduced operating costs to $13.42/bbl in the fourth quarter of 2003 from $18.30/bbl experienced during the third quarter of 2002, immediately following the acquisition of majority interests of four platforms in the Northern North Sea.
- Growth in production volumes of 18 mbbl/d or 46 percent through acquisition and exploitation work.
- Improved Environmental, Health & Safety standards, winning the Pilkington Alan Poole trophy for Behavior-Based Safety Programs in 2003.

Offshore West Africa

- The Company completed development of the East Espoir Field with production stabilizing during the fourth quarter.
- Commenced development of the Baobab Field with first production of 24 mbbl/d expected in mid-2005, increasing to 35 mbbl/d.
- Discovered oil in a satellite pool located near East Espoir which will be delineated and evaluated for development in late 2004.
- Commenced planning for the development of the West Espoir Field for first production expected in late 2005.
- Drilled unsuccessful high risk exploration well offshore Angola. Information gathered from this drill will be utilized to determine the optimal location for a second exploratory well expected in early 2005.
- Reduced operating costs by 36 percent, from $13.63/bbl to $8.68/bbl.

Horizon Project

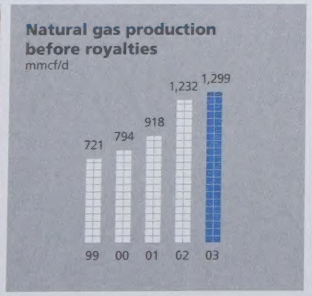
- The Company completed Design Basis Memorandum, phase II of engineering, with no material changes to cost estimates being identified.
- Phase III of engineering, Engineering Design Specification, was commenced with completion expected in 2004.
- The Company worked together with government authorities and industry groups to obtain comfort over the form of Kyoto Protocol implementation in Canada. This issue is no longer viewed as a potential impediment to the project.
- Completed regulatory applications and Joint Panel Hearings.
- Completed construction of access road, including three river spans.
- Drilled 345 stratigraphic test wells to further delineate the resources. The Company now averages 16 such wells per section on mine-site development, providing a high degree of assurance of nature and quality of ore body.

Financial strength and governance

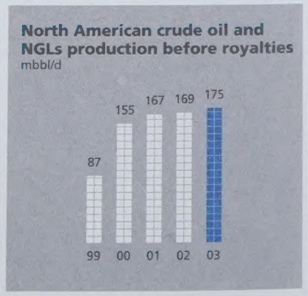
- Efficiently utilized free cash flow to greatly strengthen the balance sheet in anticipation of construction of the Horizon Project. Debt to EBITDA was reduced to 0.8 times from 1.6 times at the end of 2002.
- 2.7 million common shares were repurchased, resulting in the closing number of shares outstanding being lower than the start of the year.
- 20 percent increase in dividends announced in 2003 with a further 33 percent increase announced in early 2004.
- Added two new independent directors in 2002 with a third, an "audit committee financial expert", added late in 2003.
- Increased external evaluation of Company reserves from 90 to 100 percent. This external evaluation is supplemented by review of procedures by the Reserves Committee of the Board of Directors.

Our international portfolio is strong and delivering, now accounting for 17 percent of boe production. The Baobab development will further grow this base.

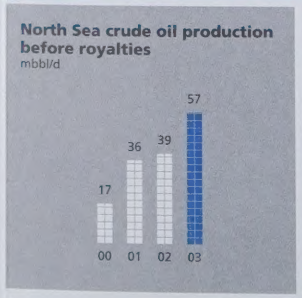
Our 2003 drilling success rate was 91 percent, reflecting our low-risk approach to the business.



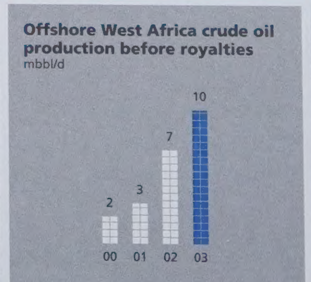
Natural gas remains our largest single product offering. Production has grown at a compounded annual rate of 16 percent.



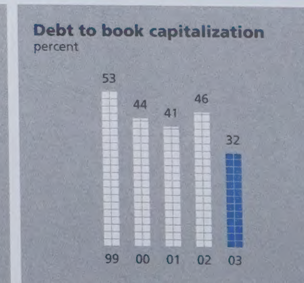
North American oil production remains strong. A new three-pronged heavy oil strategy will facilitate economic future growth.



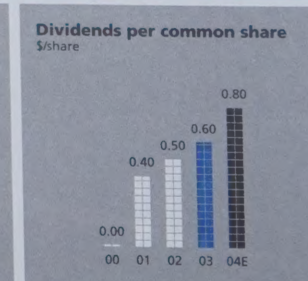
The North Sea is an exploitation base that may afford acquisition growth opportunities in the future.



Offshore West Africa is poised for further oil growth with the Baobab development commencing production in 2005 and many exploration opportunities throughout the basin.



Our balance sheet strength has grown significantly resulting in increased financial capacity to better maximize ownership of the Horizon Project.



Financial strength has resulted in significant dividend increases over the past four years as well as a small but active share buy-back program.

Our future

Our future is bright with strong opportunities to grow each of our business units. We have the financial strength and management experience to deliver on these plans.

Our domestic natural gas program is expected to deliver five percent annual production growth, while domestic oil and NGLs production will grow at an even higher rate. Our three-pronged heavy oil marketing strategy has reduced the economic risk of growing volumes ahead of limited markets.

Internationally we are known as a solid offshore producer. We have extended economic lives of our operated North Sea platforms and dropped operating costs on these platforms. This ability to drive new life into old fields will continue in this basin.

In Offshore West Africa, we have completed our first development project with a second scheduled for completion in 2005-2006. Our land base will afford significant exploration upside in this basin.

The Horizon Oil Sands Project provides a unique opportunity to construct facilities capable of producing over 232,000 barrels per day of light sweet crude for decades to come with no production declines.

On this page we present our current plans and forecasts for the next five years. These plans and estimates are subject to change as referenced on page 39.

This is how we will get there.

Clearly defined strategy for growth

By maintaining large project inventories in each basin we are able to allocate capital to maximize returns. This plan also provides planning clarity, reduces execution risk through thoughtful planning of deliverables and required inputs, and lends credence to the Company's financial and operational plan.

Continued financial discipline

Financial strength is essential to the delivery of any development plan. Canadian Natural maintains strong credit ratings and has a history of strong balance sheet management. Careful planning for the financing of the Horizon Oil Sands Project is underway and the Company believes that it will be able to maximize ownership without issuing new equity and while maintaining its strong credit ratings.

Emphasis on exploitation not high-risk exploration

The Company targets 10 percent production growth well into the future. This target is based predominantly upon lower risk exploitation programs which has always been one of the core competencies of Canadian Natural and this strength will serve us well in the future to ensure a reliable level of production and cash flow growth.

Cost control culture and approach to the business

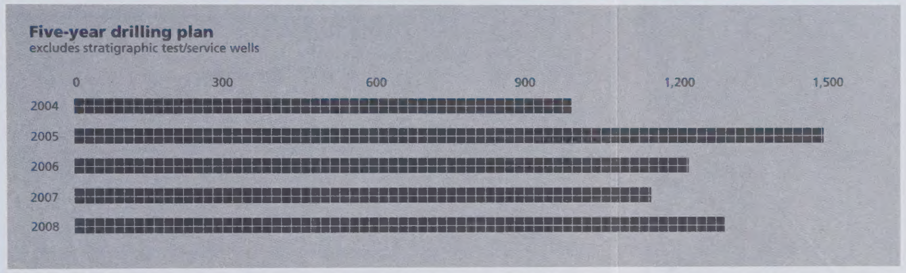
Our people are our strength and the culture that we have developed is strong. Every employee is a shareholder and every one of them is driven to add value.

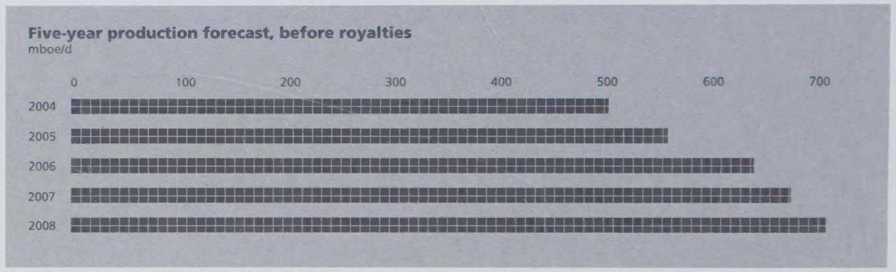
Maintain control through operating and maintaining high ownership interests

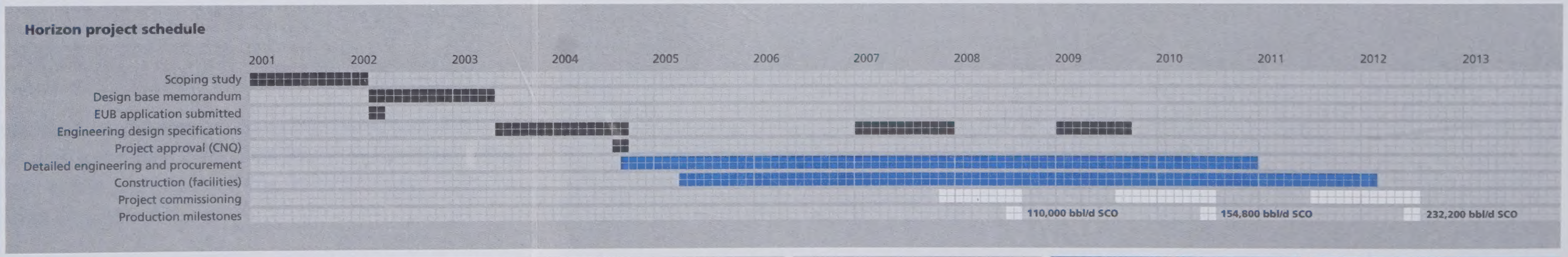
We believe that we are a strong operator and our track record speaks for itself. By gaining control over the assets, we are able to implement plans according to our optimal timeframe and approach. In this way we are less impacted by competing interests or planning restrictions of partners.

Remain balanced

Balance is an essential part of our business. We minimize exposure to single commodities and productive assets. We also ensure a consistent stream of short-term and longer, larger projects which come on during the mid- and long-term. The balancing of property acquisitions together with exploration and exploitation activities provides an optimal mix of internal and external opportunities.

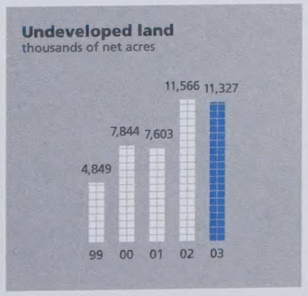




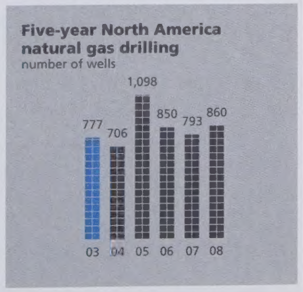


We will remain in the conventional exploration and production world…

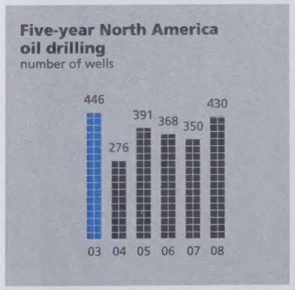
…and will augment this with a large oil sands development not available to many of our competitors.



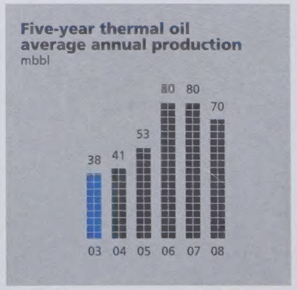
Undeveloped land is a major component in continued exploration and production success. As the second largest landholder in the WCSB, we can capitalize on both existing and newly defined resource plays.



Natural gas drilling outlook has never been so well articulated in our five-year plans, driving an expected five percent annual volume growth.



North American oil drilling continues at a strong pace following integration of the early 2004 acquisition of Petrovera.



Our exposure to the oil sands is not limited to mining. We have one of the largest and growing in-situ positions in the industry.

Our international operations provide light oil growth potential.

Our path to exceptional value creation looks bright. The construction of the access road to the Horizon Project was completed in 2003.

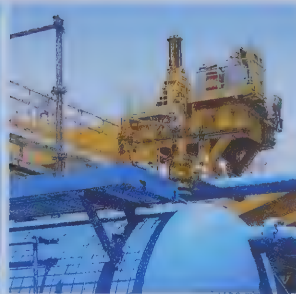
Financial highlights

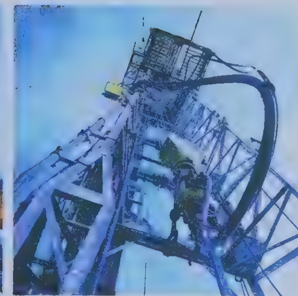
	2003	2002	2001
FINANCIAL ($ millions, except per share data)			
Revenue (1)	**$ 5,972**	$ 4,342	$ 3,757
Cash flow from operations attributable to common shareholders (2)	**$ 3,160**	$ 2,254	$ 1,920
Per common share – basic	**$ 23.54**	$ 17.63	$ 15.83
– diluted	**$ 23.06**	$ 16.99	$ 15.23
Net earnings attributable to common shareholders (3)	**$ 1,407**	$ 570	$ 642
Per common share – basic	**$ 10.48**	$ 4.46	$ 5.30
– diluted	**$ 10.14**	$ 4.31	$ 5.17
Business combinations	**$ –**	$ 2,393	$ –
Capital expenditures, net of dispositions	**$ 2,506**	$ 1,676	$ 1,885
Long-term debt	**$ 2,645**	$ 4,074	$ 2,669
Shareholders' equity	**$ 6,117**	$ 4,868	$ 3,806

(1) Restated to conform to current year presentation.
(2) After dividend on preferred securities.
(3) After dividend and revaluation of preferred securities.

	2003	2002	2001
OPERATING			
Daily production before royalties			
Crude oil and NGLs (mbbl/d)			
North America	**175**	169	167
North Sea	**57**	39	36
Offshore West Africa	**10**	7	3
	242	215	206
Natural gas (mmcf/d)			
North America	**1,245**	1,204	906
North Sea	**46**	27	12
Offshore West Africa	**8**	1	–
	1,299	1,232	918
Barrel of oil equivalent (mboe/d)	**459**	421	359
Average prices before royalties			
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 27.77**	$ 27.04	$ 21.00
North Sea	**$ 42.43**	$ 39.79	$ 38.66
Offshore West Africa	**$ 36.47**	$ 40.10	$ 33.57
Company average	**$ 31.59**	$ 29.76	$ 24.31
Natural gas ($/mcf) (1)			
North America	**$ 6.14**	$ 3.78	$ 5.19
North Sea	**$ 3.03**	$ 2.75	$ 2.51
Offshore West Africa	**$ 4.37**	$ 4.82	$ –
Company average	**$ 6.02**	$ 3.76	$ 5.16
Drilling activity (net wells, excluding stratigraphic test/service wells)			
North America	**1,338**	444	736
North Sea	**13**	5	2
Offshore West Africa	**2**	4	1
	1,353	453	739
Core undeveloped land holdings (thousands of net acres)			
North America	**9,811**	10,213	6,272
North Sea	**573**	410	237
Offshore West Africa	**943**	943	1,094

(1) Includes financial instruments and transportation costs.

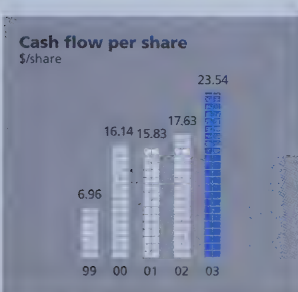




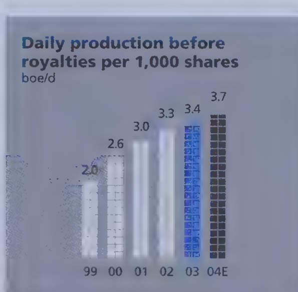
Proved reserves before royalties	2003	2002	2001
Crude oil and NGLs (mmbbl)			
North America	**672**	665	644
North Sea	**222**	203	83
Offshore West Africa	**106**	94	61
	1,000	962	788
Natural gas (bcf)			
North America	**3,006**	3,048	2,566
North Sea	**62**	71	94
Offshore West Africa	**86**	90	69
	3,154	3,209	2,729
Barrels of oil equivalent (mmboe)	**1,526**	1,497	1,243

Proved reserves after royalties	2003	2002	2001
Crude oil and NGLs (mmbbl)			
North America	**588**	571	583
North Sea	**222**	202	78
Offshore West Africa	**85**	75	60
	895	848	721
Natural gas (bcf)			
North America	**2,426**	2,446	2,064
North Sea	**62**	71	94
Offshore West Africa	**64**	71	67
	2,552	2,588	2,225
Barrels of oil equivalent (mmboe)	**1,320**	1,279	1,092

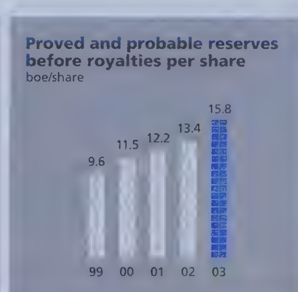
We strive to grow our four value creation metrics by an average of 10 percent per year over a measured five-year period, a rate which we have well exceeded. We believe that these metrics drive share valuations for exploration and production companies over the long run and that our defined growth plan will allow for continued growth into the future.



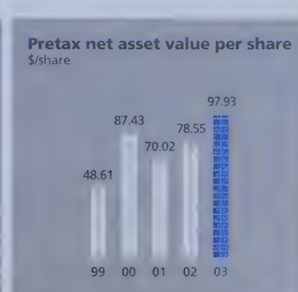
Cash flow growth reflects higher production levels as well as commodity price impacts. Compound growth rate in period shown is 36 percent per year.



Compound growth rate in period shown is 13 percent per year.



Compound growth rate in period shown is 13 percent per year. See reserves disclosure footnotes on pages 14 to 17.



Based upon 10% discounted escalated price case asset values for proved and probable reserves as disclosed in the AIF with $75/acre added for undeveloped land, less long-term debt and existing asset liabilities. Includes value of midstream assets.

Letter to shareholders

Allan P. Markin
Chairman

N. Murray Edwards
Vice-Chairman

John G. Langille
President

Steve W. Laut
Chief Operating Officer

The year 2003 was another record year for Canadian Natural, "the Premium Value, Defined Growth Independent", and reflected the continued execution of our defined growth strategy to create shareholder value. Record annual cash flow and earnings were a direct result of drilling success, operational efficiency and high commodity prices. We also achieved significant progress on our larger, future-growth projects while maintaining our focus on existing assets, both in North America and internationally. Our proven and effective strategies continue to provide a strong and well articulated approach for future growth. As we enter 2004 we know that we are well positioned to deliver above average growth throughout the coming decade.

Our strategy is predicated upon maintaining a large inventory of projects for each of our products and in each of the basins in which we operate. By having this inventory of choices we are able to continually highgrade our development plans in order to achieve superior returns. The process of allocating our capital is achieved through our strong team based culture, which seeks to:

- Provide product balance between natural gas and various grades of crude oil and NGLs;
- Ensure a stream of projects providing production growth in the near-, mid- and long-terms;
- Ensure long term economic returns at normalized commodity prices; and
- Maintain a low-risk exploitation focus while still providing some exploration upside and allowing for opportunistic acquisitions.

Our focus remains clear. By concentrating in and focusing on our core regions and controlling and dominating the infrastructure in these core regions, we are able to:

- Better control costs by maximizing utilization of our assets;
- Better understand the basins in which we operate, facilitating a lower risk approach to the business;
- Plan comprehensive annual and long-term development strategies, which afford economies of scale; and
- Effectively direct and manage operations of individual projects while still stewarding to overall corporate plans and objectives.

We also control the nature and pace of development of each of our assets by maintaining high ownership interests and operating almost every asset we own. In 2003 we further consolidated positions in the North Sea and now operate approximately 99 percent of our production – a level more typical to our strategy.

A key to success associated with this strategy is to hire the right people at the right time. We have been able to attract quality individuals with lengthy experience and significant knowledge in each area of our business. Our Company's reporting and management systems allow our employees to develop our projects in a controlled and disciplined manner.

The strength of our asset base has never been as apparent as it is today, with every division possessing a deep portfolio of opportunities.

North American Natural Gas

Canadian Natural remains a significant producer of natural gas in North America, representing about 8 percent of western Canadian output. During 2003 we completed the integration of Rio Alto Exploration Ltd., with the assets showing the potential seen when they were originally purchased. Through the dedication of technical resources we have found ways to lower the exploration risk associated with the complex Cardium formation and decrease drilling and completion costs by over 50 percent from those previously incurred. The focus on extracting value through developing new play types on the land has also resulted in a significant increase in the number of future drilling locations for other Cretaceous and deeper targets.

In Northeast British Columbia our attention to detail and area knowledge have led to the discovery of a new shallow gas play. This play will provide up to 450 locations over the next five years and will leverage our shallow gas drilling expertise gained in our South Alberta core region. This latter region, along with North Alberta, are more mature areas where our extensive infrastructure and land base allow us to continually develop leads and prospects where others may not be able to economically succeed.

North American Crude Oil and NGLs

As one of Canada's largest producers of crude oil and as a major holder of extensive oil prone lands and bitumen leases, Canadian Natural continues its key role in North America's energy future. We have decades of development projects to bring on production over time and now, with our three-pronged heavy oil marketing strategy, the opportunity to economically produce these assets is stronger than ever. We continue to look for opportunities to work with pipeline companies to gain access to new markets in North America and abroad. We are willing to work together with refiners to create additional conversion capacity for heavy oil products. Finally, our plan to blend heavy oil/bitumen with synthetic light crude oil to create "Synbit" is already showing progress. Synbit is a direct competitor with medium sour crude oil and does not require any upgrading on the part of the refiner. Having only been articulated in late 2003, the Company is already a leader in building the Synbit market. In early 2004 we are supplying four refiners in the US Midwest with trial volumes. If successful, this could lead to the creation of additional heavy oil markets in a short time with very little capital requirements. While it is too early to assume that the Synbit strategy will work, management believes that the three-pronged marketing strategy will, over time, deliver the markets necessary to economically develop the vast potential of the Company's asset base.

International Crude Oil

In the North Sea, Canadian Natural remains excited about the exploitation opportunities surrounding its assets in the Northern and Central North Sea. Productive lives of the four producing platforms at Ninian and Murchison have been extended through waterflood management and infill drilling.

In Côte d'Ivoire located offshore West Africa, development of the Espoir Field was completed in 2003 with production stabilized late in the year. The Baobab Field also commenced development with first production of approximately 24 mbbl/d expected in mid-2005 with further increases to 35 mbbl/d expected thereafter. The West Espoir development provides further production upside in 2006 and near-pool exploration upside exists with the future delineation of the Acajou discovery and exploration drilling of other satellite pools. Finally, further exploration drilling of our operated and 50 percent owned Block 16 located offshore Angola will provide high impact exploration upside in 2005.

Horizon Oil Sands Project

This project will seek to develop over 6 billion barrels of mineable bitumen resources with 232 mbbl/d of light sweet synthetic crude oil being produced by 2012. During 2003, regulatory submissions were made with many of the required approvals having been received in early 2004. Our approach to developing this capital intensive project is to achieve a higher degree of upfront engineering and planning than has been previously accomplished on similar projects in Alberta. We believe that more upfront effort will increase cost certainty of the project, a prerequisite to final Board of Directors approval expected in 2004.

The scheduling of commencement of construction will remain flexible to accommodate Management's intent to obtain this cost certainty. Canadian Natural remains confident of its ability to deliver this project and has created a team of professionals capable of delivering this world class opportunity to our shareholders.

Financial Capability

Our team is disciplined when using financial leverage. Immediately following the acquisition of Rio Alto in 2002, a plan was put in place to restore our financial strength to previous levels. Higher than expected commodity prices enabled the further reduction of debt. During 2003, debt to capitalization levels fell from a manageable 46 percent to a low 32 percent, well below our targeted levels for our credit ratings. This strong balance sheet allows further opportunistic acquisitions such as the early 2004 purchase of heavy oil properties in our North Alberta core region without compromising our ability to finance the Horizon Project. We are opportunistically using the balance sheet to build a larger company capable of financing a large, capital intensive opportunity like the Horizon Project without curtailing our ongoing conventional operations.

While maintaining this financial prudence we are also able to provide our shareholders with additional returns through a small share repurchase program and the third consecutive increase in dividends following the creation of the dividend program four years ago.

Corporate Governance

Effective governance is critical to building a successful company for the 21st century. During 2002 we established new independent committees of the Board of Directors and added two new independent directors. We followed this up in 2003 with the appointment of another independent Board member, who also qualifies as our "audit committee financial expert".

We are well positioned for continued growth and development in each of our product offerings and basins and we have the financial strength necessary to deliver without compromising our strategy. We are proud to represent our stakeholders and believe that we have assembled a skilled team of committed employees and an asset portfolio that provides a clear path to profitable growth.

Allan P. Markin
Chairman

N. Murray Edwards
Vice-Chairman

John G. Langille
President

Steve W. Laut
Chief Operating Officer

Global operations

North America

As our major production base, we see excellent opportunities for continued growth in natural gas and heavier grades of crude oil. As the second largest landholder in the basin, we have access to a variety of new and well established play types. We also have a very strong presence in the oil sands with extensive development projects utilizing both in-situ and open pit mining techniques.

North Sea

We operate four oil producing platforms and two FPSOs in the UK sector of the North Sea and we view this basin as being similar to the WCSB of the early 1990s. Existing landholders are slowly exiting the basin, providing exploitation opportunities that are well aligned with our core competencies. The existing asset base provides enough opportunities to maintain production volumes for the next few years, after which, absent new acquisitions, production is expected to slowly decline from this basin.

Offshore West Africa

This region is a very prolific basin for the exploration of light oil. Our main development and exploration activity is centered in Côte d'Ivoire, which is characterized by 100-200 million barrel pools, too small for the super majors to target. We expect that our land base here will provide over a decade of exploration and development activities. Our operated Block 16 located offshore Angola provides a high risk/high potential light oil exploration opportunity. We drilled one unsuccessful well here in late 2003 and utilizing our knowledge from that well, are targeting to drill a second well in early 2005.

North America

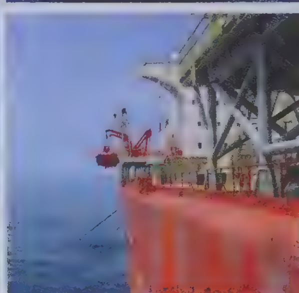
	2003 results, after royalties	
	Production (mboe/d)	Proved reserves (mmboe)
Crude oil and NGLs	**154**	**588**
Natural gas	**162**	**404**
Boe	**316**	**992**
% of total	**80**	**75**

For 2004, natural gas volumes are expected to grow by approximately 6 percent. While light oil and NGLs and Pelican Lake production will remain relatively flat, growth in thermal heavy oil production of approximately 3 to 5 mbbl/d is anticipated. Conventional heavy oil production will increase by approximately 25-30 mbbl/d due to drilling activity and the early 2004 Petrovera acquisition.

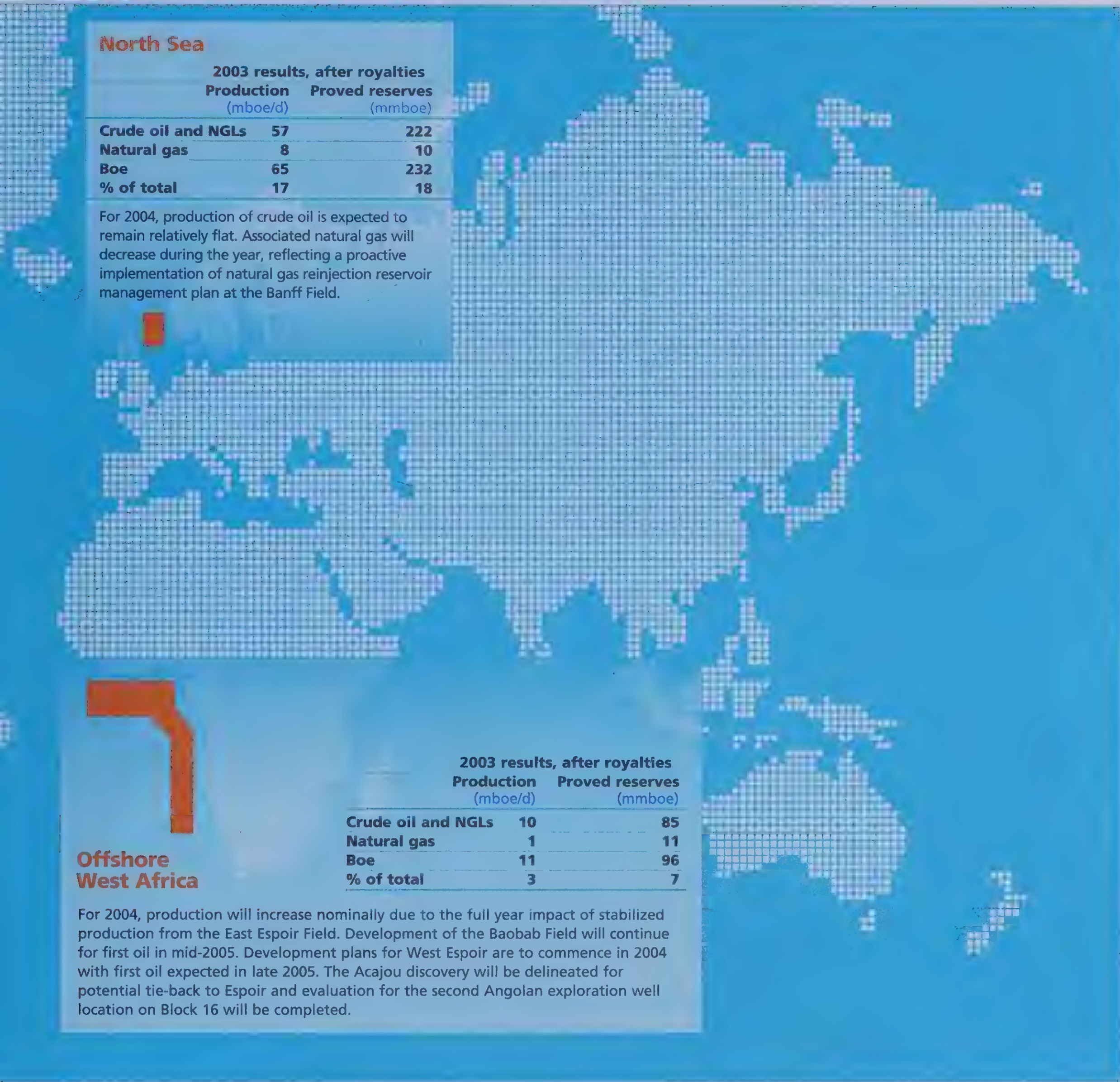
Primrose thermal oil pad
In-situ production is completed from efficient 24 well groupings, which minimize surface disturbance.

Ninian North Platform
One of four platforms operated by us in the Northern North Sea.

Natural gas exploration
We are a very active natural gas driller, including shallow, medium and deep targets. We also target tight gas sands at Helmet in Northeast British Columbia and the Cardium in Northwest Alberta.



Espoir Ivorien
Our operated FPSO located in shallow water off the coast of Côte d'Ivoire.



North Sea

	Production (mboe/d)	Proved reserves (mmboe)
	2003 results, after royalties	
Crude oil and NGLs	57	222
Natural gas	8	10
Boe	65	232
% of total	17	18

For 2004, production of crude oil is expected to remain relatively flat. Associated natural gas will decrease during the year, reflecting a proactive implementation of natural gas reinjection reservoir management plan at the Banff Field.

Offshore West Africa

	Production (mboe/d)	Proved reserves (mmboe)
	2003 results, after royalties	
Crude oil and NGLs	10	85
Natural gas	1	11
Boe	11	96
% of total	3	7

For 2004, production will increase nominally due to the full year impact of stabilized production from the East Espoir Field. Development of the Baobab Field will continue for first oil in mid-2005. Development plans for West Espoir are to commence in 2004 with first oil expected in late 2005. The Acajou discovery will be delineated for potential tie-back to Espoir and evaluation for the second Angolan exploration well location on Block 16 will be completed.

North American oil

Pelican Lake waterflood conversion
Primrose South high pressure conversion*
Primrose North development*
Wolf Lake plant de-bottleneck*
Burnt Lake steam generation plant*

** In-Situ projects, excluding ongoing drilling activity*

Offshore West Africa

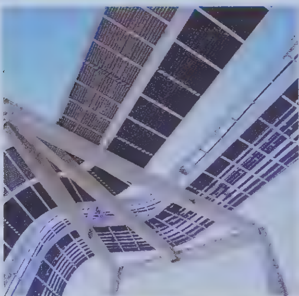
Baobab development
West Espoir development
Acajou exploration, assuming success
Block 16 exploration, offshore Angola

Ninian North water injection

The expenditure of funds to upgrade waterflood infrastructure seems counterintuitive on a mature pool, where the objective is to reduce costs. However, Canadian Natural views costs on a per barrel basis, meaning that sometimes the best way to drop costs is to increase production. In this example, the water injectors were upgraded and became more reliable with instantaneous and dramatic results

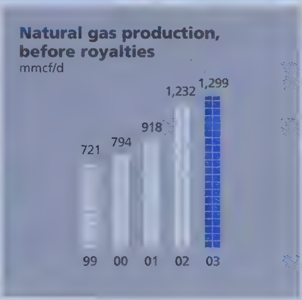
Review of operations

Capital discipline is essential to provide economic returns over the long-run.

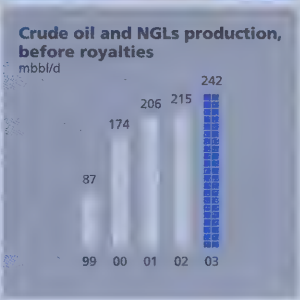


Douglas A. Proll
Senior Vice-President, Finance

Lyle G. Stevens
Senior Vice-President, Exploitation



Our four core regions for natural gas production have provided consistent growth opportunities.



Our core regions allow for disciplined growth with an exploitation focus.

Production

The Company's natural gas sales increased by 5 percent in 2003, averaging 1,299 mmcf/d before royalties compared with 1,232 mmcf/d in 2002. Production increases reflected a 777 well drilling program in 2003 as well as the mid-2002 acquisition of Rio Alto. Increases from these items were partially offset by steep year over year production declines at Ladyfern and the government mandated shut-in of natural gas production in the Athabasca Wabiskaw-McMurray oilsands area for bitumen conservation purposes.

Crude oil and NGLs production averaged 242.4 mbbl/d before royalties in 2003, up 13 percent from 2002 levels largely as a result of a 73 percent increase in drilling activity. North American liquids production increased 3 percent from 2002 due to increased NGLs production associated with higher natural gas production. Higher heavy oil production reflected increased drilling. Pelican Lake and thermal heavy oil volumes decreased due to lower drilling activity on these properties.

Approximately 18 mbbl/d in North Sea production increases were realized through a combination of property acquisitions and an extensive exploitation waterflood management and infill drilling program. Canadian Natural now operates approximately 99 percent of its production and owns an average of 80 percent in these properties, allowing it to implement its exploitation programs. As a result of the continued development of the Espoir Field in Côte d'Ivoire, Offshore West Africa oil production growth of 3.8 mbbl/d was realized. Production from this field has now stabilized at approximately 12 mbbl/d net to Canadian Natural.

Canadian Natural's producing asset mix remains balanced between natural gas and various grades of crude oil and NGLs. Heavy, thermal and Pelican Lake oil decreased as a percentage of total mix from 30 percent to 28 percent, providing greater balance between lighter and heavier grades of crude oil.

	2003		2002	
(before royalties)	**Production** mboe/d	**Mix** %	Production mboe/d	Mix %
Natural gas	**217**	**47**	206	49
North America light crude oil and NGLs	**47**	**10**	42	10
Pelican Lake crude oil	**24**	**5**	29	7
Primary heavy crude oil	**66**	**15**	59	14
Thermal heavy crude oil	**38**	**8**	39	9
North Sea light crude oil	**57**	**13**	39	9
Offshore West Africa light crude oil	**10**	**2**	7	2
Total	**459**	**100**	421	100

Seismic

Canadian Natural continues to be active in adding quality locations to our inventory by integrating geological plays with seismic data analysis.

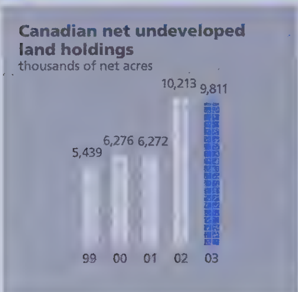
For the year 2003 in Canada, the Company invested $48 million to acquire new seismic and to purchase and reprocess existing seismic data. In total over 3,160 kilometers of conventional 2-D seismic data and over 181 square kilometers of 3-D seismic data were acquired.

Additionally, over 5,400 kilometers of conventional 2-D seismic data and 315 square kilometers of 3-D seismic data were purchased. We continue to acquire this data under stringent environmental controls in a cost effective manner.

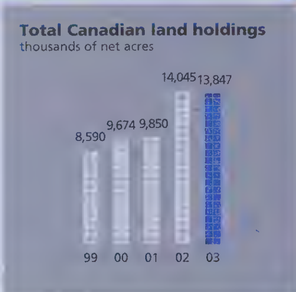
In the North Sea, the Company purchased 25,953 kilometers of 2-D seismic and reprocessed a further 161 square kilometers of 3-D seismic data. This data allows Canadian Natural to continue aggressive in-field and near-field development and exploration.

Offshore West Africa saw the purchase of 3,589 kilometers of 2-D seismic data and the reprocessing of 1,066 square kilometers of 3-D seismic data.

Review of operations

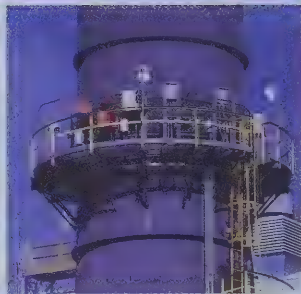


Undeveloped land is critical to successful ongoing exploitation activity. Canadian Natural has one of the largest bases.



As the second largest landholder in the Western Canadian Sedimentary Basin, the Company can capitalize on a variety of new and established play types.

Mary-Jo E. Case
Vice-President, Land



Undeveloped land

Canadian Natural owns the second largest undeveloped land inventory in the WCSB. During 2003, the Company's undeveloped net acreage totaled 9.8 million net acres, slightly below the 10.2 million net acres in 2002. Total land holdings in the WCSB were 13.8 million net acres at the end of 2003, similar to prior year figures.

This strong land base affords significant opportunities to maintain high utilization of existing infrastructure and keep costs low. It also positions the Company to take advantage of new play types developed by ourselves and other producers adjacent to our core operating areas. For example, the Ladyfern Field was discovered in 2000 by another producer on lands adjacent to an operated shallow gas development, allowing access to approximately 100 bcf of natural gas which has been produced to date from these lands.

Similarly, our Northwest Alberta core region is estimated to contain approximately 0.2 million acres of potential exploration for the Cadomin formation, a tight gas productive horizon now being targeted by industry. This represents further upside potential not originally factored into the acquisition of Rio Alto. In addition, we leveraged our vast Northeast British Columbia land base to correlate well data to develop a new regional shallow natural gas play.

Internationally, our undeveloped land base has increased to 0.6 million acres in the North Sea, up from 0.4 million acres in 2002. Offshore West Africa acreage remained flat at 0.9 million acres.

The Company's average landholding working interest of 79 percent reflects the Company's approach to maintain high ownership levels and control operations.

Core Landholdings

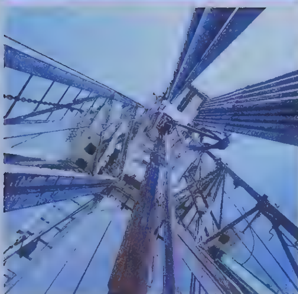
	2003			2002		
(thousands of acres)	**Gross**	**Net**	**Average interest %**	Gross	Net	Average interest %
Canada						
Developed	**5,266**	**4,036**	**77**	5,013	3,832	76
Undeveloped	**11,776**	**9,811**	**83**	12,241	10,213	83
	17,042	**13,847**	**81**	17,254	14,045	81
North Sea						
Developed	**106**	**65**	**61**	106	56	52
Undeveloped	**804**	**573**	**71**	733	410	56
Offshore West Africa						
Developed	**8**	**5**	**59**	8	5	59
Undeveloped	**1,673**	**943**	**56**	1,673	943	56
Total	**19,633**	**15,433**	**79**	19,774	15,459	78

Drilling activity

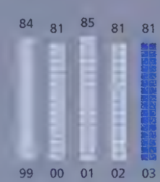
During the year, the Company drilled a total of 1,793 net wells, almost twice 2002 levels. In particular, natural gas drilling increased to almost five times the level of activity experienced in the prior year, while crude oil drilling increased 73 percent. The increase in natural gas drilling is reflective of the Company's proactive decision to defer drilling prospects in 2002 in anticipation of Ladyfern production declines. During 2003, the Company drilled 440 net stratigraphic test/service wells, principally on the oil sands leases in the Horizon Oil Sands Project and in North Alberta.

An overall success rate of 91 percent was achieved through a predominantly exploitation based program.

The Company's natural gas drilling occurred across four of its five core regions: Northeast British Columbia, Northwest Alberta, North Alberta and South Alberta. Of the 777 natural gas wells that were drilled, 363 were high density wells targeting shallow natural gas plays. In North America, conventional heavy oil drilling accounted for 315 wells, with 51 light oil wells being drilled.

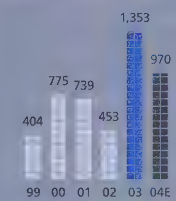


Net average interest Canadian landholdings
percent



High working interests allows development according to Canadian Natural's own plans and strategies.

Total net wells drilled
excludes stratigraphic test / service wells



Reflecting prudent capital management practices the 2004 drilling program was reduced following the early 2004 Petrovera acquisition.

Additionally, the Company's Primrose drilling program continued with 41 new thermal wells drilled during 2003. With steaming having commenced in early 2004, first production from these new wells is expected in mid 2004. Conventional production from the Pelican Lake Field reflected no drilling activity during the second half of 2003 with a total of 39 wells drilled in 2003. Canadian Natural views its 2003 Enhanced Oil Recovery waterflood test program as a success and as such, Canadian Natural will begin the phased roll out of the waterflood with approximately 20 percent of the field being under waterflood by the end of 2004.

The waterflood will stabilize production, but will require a further 63 Pelican Lake productive wells to be converted from producer to water injectors and 43 new wells to be drilled as producers.

In the North Sea, the Company drilled 11 oil wells and five water injector wells. Two unsuccessful exploration wells were drilled, one at Murchison and the other offshore France. In Côte d'Ivoire, Canadian Natural drilled one oil well and two water injection wells. One unsuccessful exploration well was also drilled in Angola.

Drilling Activity

	2003		2002	
(number of wells)	**Gross**	**Net**	Gross	Net
Natural gas	**841**	**777**	183	162
Oil	**490**	**458**	316	264
Dry	**126**	**118**	32	27
	1,457	**1,353**	531	453
Stratigraphic test/service	**447**	**440**	456	447
Total	**1,904**	**1,793**	987	900
Success rate; excluding stratigraphic test/service wells		**91%**		94%

Core Region Focus

	Net undeveloped land (thousands of acres)		**Drilling activity** (net wells)	
	2003	2002	**2003**	2002
Northeast British Columbia	**1,566**	1,513	**106**	48
Northwest Alberta	**1,681**	1,821	**121**	13
North Alberta	**5,627**	5,935	**717**	475
South Alberta	**673**	666	**430**	55
Southeast Saskatchewan	**147**	161	**27**	5
Horizon Oil Sands Project	**117**	117	**370**	293
North Sea	**573**	410	**18**	6
Offshore West Africa	**943**	943	**4**	5
Total	**11,327**	11,566	**1,793**	900

Reserves and reserves replacements

For the year ended December 31, 2003, the Company retained independent qualified petroleum engineering consultants Sproule Associates Limited ("Sproule") to evaluate 100 percent of the Company's proved and probable crude oil and natural gas reserves and prepare evaluation reports on the Company's total reserves ("Evaluation Reports"). The Board of Directors' Reserves Committee has met with Sproule and carried out independent due diligence procedures with Sproule as to the Company's reserves.

The Company has been granted an exemption from the recently adopted National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") which prescribes the standards for the preparation and disclosure of reserves and reserves related information for companies listed on stock exchanges in Canada. This exemption allows the Company to substitute United States Security and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. The primary difference between the two standards is the additional requirement under NI 51-101 to disclose both proved, and proved and probable reserves, as well as related future net revenues, using forecast prices and costs. Another difference between the two standards lies in the definition of proved reserves.

As discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards which NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the NI 51-101 and SEC standards is not material.

In accordance with the exemption, the Company has disclosed proved reserves using constant prices and costs as mandated by the SEC. The Company has elected to provide proved and probable reserves and values under the same economic parameters as additional voluntary information.

In Sproule's evaluation, 34 percent of the Company's total proved boes has been assigned to proved undeveloped ("PUDs") which is consistent with 33 percent in 2002.

The majority of the Company's crude oil and NGLs PUDs are associated with:

- The Primrose thermal project, where tertiary recovery performance has been proven and the pool has been delineated to justify future expansions; and
- The development of the Baobab pool in Côte d'Ivoire where drilling has established proved reserves.

Sproule has assigned PUDs to 14 percent of the total Corporate proved natural gas reserves, of which are mainly associated with solution gas conservation projects, low risk infill drilling, and natural gas in secondary horizons.

Net reserves classification by product (%)

(As at December 31, 2003)

	Proved developed (2)	Proved undeveloped (2)	Proved total (2)	Proved and probable (3)
Light oil and NGLs				
North America	7	–	7	6
North Sea	10	6	16	17
Offshore West Africa	2	5	7	7
Total	19	11	30	30
Heavy oil				
North America – Pelican Lake	2	1	3	4
North America – Primary	6	1	7	6
North America – Thermal	11	16	27	31
Total	19	18	37	41
Total crude oil and NGLs				
North America	26	18	44	47
North Sea	10	6	16	17
Offshore West Africa	2	5	7	7
Total	38	29	67	71
Natural gas				
North America	27	4	31	27
North Sea	1	–	1	1
Offshore West Africa	–	1	1	1
Total	28	5	33	29
Total boe	66	34	100	100

Finding and onstream costs

	2003	2002	2001	Three year total
Net reserve replacement expenditures	**$ 2,283**	$ 3,928	$ 1,745	**$ 7,956**
Reserve additions [8] (mmboe, net of royalties)				
Proved	**185**	317	172	**674**
Proved and probable	**441**	356	206	**1,003**
Finding and development costs per boe [9] (per boe, net of royalties)				
Proved	**$ 12.34**	$ 12.39	$ 10.15	**$ 11.80**
Proved and probable	**$ 5.18**	$ 11.03	$ 8.47	**$ 7.93**

Net reserves summary

Reserves, net of royalties [1]

	December 31, 2003			
	Proved developed [2]	**Proved undeveloped** [2]	**Proved total** [2]	**Proved and probable** [3]
Crude oil and NGLs (mmbbl)				
North America	**348**	**240**	**588**	**857**
North Sea	**138**	**84**	**222**	**317**
Offshore West Africa	**23**	**62**	**85**	**133**
	509	**386**	**895**	**1,307**
Natural gas (bcf)				
North America	**2,140**	**286**	**2,426**	**2,919**
North Sea	**46**	**16**	**62**	**102**
Offshore West Africa	**12**	**52**	**64**	**72**
	2,198	**354**	**2,552**	**3,093**
Total reserves (mmboe)	**875**	**445**	**1,320**	**1,823**
Reserve replacement ratio [4] (%)			**129**	**308**
Cost to develop [5] ($/boe)				
10% discount	**0.24**	**4.02**	**1.51**	**1.60**
15% discount	**0.22**	**3.69**	**1.39**	**1.44**
Present value of reserves [6] ($ million)				
10% discount	**13,079**	**3,037**	**16,116**	**20,164**
15% discount	**11,222**	**2,273**	**13,495**	**16,460**

	December 31, 2002			
	Proved developed [7]	Proved undeveloped [7]	Proved total [7]	Proved and probable [7]
Crude oil and NGLs (mmbbl)				
North America	340	231	571	636
North Sea	107	95	202	277
Offshore West Africa	27	48	75	121
	474	374	848	1,034
Natural gas (bcf)				
North America	2,185	261	2,446	2,765
North Sea	57	14	71	89
Offshore West Africa	27	44	71	90
	2,269	319	2,588	2,944
Total reserves (mmboe)	852	427	1,279	1,525
Reserve replacement ratio [4] (%)			245	275
Cost to develop [5] ($/boe)				
10% discount	0.42	3.85	1.57	1.53
15% discount	0.37	3.45	1.40	1.37
Present value of reserves [6] ($ million)				
10% discount	15,485	3,850	19,335	20,965
15% discount	13,306	2,871	16,177	17,426

Net reserves reconciliation

Crude oil and NGLs reconciliation (1) (mmbbl, net of royalties)	North America	North Sea	Offshore West Africa	Total
PROVED RESERVES (2)				
Reserves, December 31, 2001	583	78	60	721
Extensions and discoveries	26	1	14	41
Property purchases	44	114	–	158
Property disposals	(1)	(18)	–	(19)
Production	(55)	(13)	(2)	(70)
Revisions of prior estimates	(26)	40	3	17
Reserves, December 31, 2002	571	202	75	848
Extensions and discoveries	**1**	**–**	**13**	**14**
Infill drilling	**54**	**–**	**–**	**54**
Improved recovery	**9**	**–**	**–**	**9**
Property purchases	**7**	**27**	**–**	**34**
Property disposals	**–**	**–**	**–**	**–**
Production	**(56)**	**(21)**	**(4)**	**(81)**
Revisions of prior estimates	**2**	**14**	**1**	**17**
Reserves, December 31, 2003	**588**	**222**	**85**	**895**
PROVED AND PROBABLE RESERVES (3)				
Reserves, December 31, 2001	670	100	103	873
Extensions and discoveries	26	–	5	31
Property purchases	52	138	–	190
Property disposals	(1)	(22)	–	(23)
Production	(55)	(13)	(2)	(70)
Revisions of prior estimates	(56)	74	15	33
Reserves, December 31, 2002	636	277	121	1,034
Extensions and discoveries	**1**	**–**	**17**	**18**
Infill drilling	**58**	**–**	**–**	**58**
Improved recovery	**25**	**–**	**12**	**37**
Property purchases	**10**	**33**	**–**	**43**
Property disposals	**–**	**–**	**–**	**–**
Production	**(56)**	**(21)**	**(4)**	**(81)**
Revisions of prior estimates	**183**	**28**	**(13)**	**198**
Reserves, December 31, 2003	**857**	**317**	**133**	**1,307**

(1) Reserve estimates and present value calculations are based upon constant reference price assumptions as detailed below. A foreign exchange rate of US$0.77/C$1.00 was used in the 2003 evaluation. A foreign exchange rate of US$0.63/C$1.00 was used in the 2002 evaluation.

RESERVES EVALUATION PRICING MODELS

Crude oil and NGLs	Company average price (C$/bbl)	WTI @ Cushing Oklahoma (US$/bbl)	Hardisty Heavy 12° API (C$/bbl)	North Sea Brent (US$/bbl)
December 31, 2003	**32.02**	**32.56**	**26.16**	**30.14**
December 31, 2002	39.23	31.23	35.04	30.21

Natural gas	Company average price (C$/mcf)	Henry Hub Louisiana (US$/mcf)	Alberta AECO C (C$/mcf)	British Columbia Huntingdon Sumas (C$/bbl)
December 31, 2003	**6.63**	**5.80**	**6.88**	**6.94**
December 31, 2002	5.88	4.59	5.97	6.53

(2) 2003 proved reserve estimates and values were evaluated in accordance with COGEH standards as modified to meet the SEC requirements. The stated reserves have a reasonable certainty of being economically recoverable using year-end prices and costs held constant throughout the productive life of the properties.

Natural Gas Reconciliation (1) (bcf, net of royalties)	North America	North Sea	Offshore West Africa	Total
PROVED RESERVES (2)				
Reserves, December 31, 2001	2,064	94	67	2,225
Extensions and discoveries	106	–	4	110
Property purchases	699	18	–	717
Property disposals	(3)	(56)	–	(59)
Production	(346)	(10)	(1)	(357)
Revisions of prior estimates	(74)	25	1	(48)
Reserves, December 31, 2002	2,446	71	71	2,588
Extensions and discoveries	**58**	**–**	**6**	**64**
Infill drilling	**243**	**–**	**–**	**243**
Improved recovery	**8**	**–**	**–**	**8**
Property purchases	**50**	**19**	**–**	**69**
Property disposals	**(3)**	**–**	**–**	**(3)**
Production	**(355)**	**(17)**	**(3)**	**(375)**
Revisions of prior estimates	**(21)**	**(11)**	**(10)**	**(42)**
Reserves, December 31, 2003	**2,426**	**62**	**64**	**2,552**
PROVED AND PROBABLE RESERVES (3)				
Reserves, December 31, 2001	2,344	118	88	2,550
Extensions and discoveries	112	–	(7)	105
Property purchases	764	24	–	788
Property disposals	(3)	(62)	–	(65)
Production	(346)	(10)	(1)	(357)
Revisions of prior estimates	(106)	19	10	(77)
Reserves, December 31, 2002	2,765	89	90	2,944
Extensions and discoveries	**72**	**–**	**11**	**83**
Infill drilling	**285**	**–**	**–**	**285**
Improved recovery	**26**	**–**	**(6)**	**20**
Property purchases	**59**	**22**	**–**	**81**
Property disposals	**(3)**	**–**	**–**	**(3)**
Production	**(355)**	**(17)**	**(3)**	**(375)**
Revisions of prior estimates	**70**	**8**	**(20)**	**58**
Reserves, December 31, 2003	**2,919**	**102**	**72**	**3,093**

(3) 2003 proved and probable reserve estimates and values were evaluated in accordance with COGEH standards and as mandated by NI 51-101. The stated reserves have a 50% probability of equaling or exceeding the indicated quantities and were evaluated using year-end costs and prices held constant throughout the productive life of the properties.

(4) Reserve replacement ratios were calculated using annual net boe reserve additions comprised of all change categories divided by the net production for that year.

(5) Cost to develop represents total future capital for each reserves category excluding abandonment capital divided by the reserves associated with that category.

(6) Present value of reserves are based upon discounted cash flows associated with prices and operating expenses held constant into the future, before income taxes. Only future development costs and abandonment costs have been applied against future net revenues. Values include midstream assets.

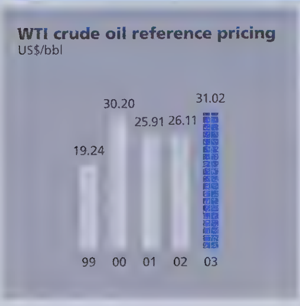
(7) 2002 reserve estimates were evaluated in accordance with the standards of National Policy 2-B which has now been replaced by NI 51-101. The stated reserves were reasonably evaluated as economically productive using year-end costs and prices held constant throughout the productive life of the properties.

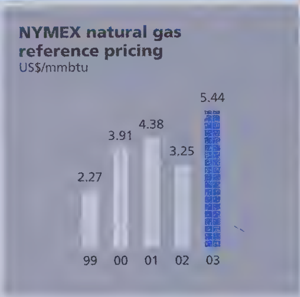
(8) Reserves additiohs are comprised of all categories of reserves changes, exclusive of production.

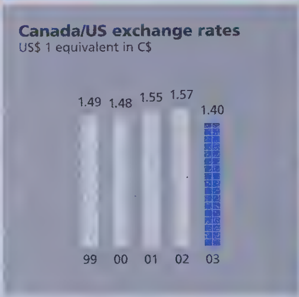
(9) Reserves finding and onstream costs are determined by dividing total capital costs for each year excluding costs associated with head office, abandonments, midstream and Project Horizon by reserves additions for that year.

Marketing

Our three-pronged heavy oil marketing strategy seeks to expand markets through addition of new conversion capacity, expand markets through new pipelines and target new markets through Synbit.







Natural gas

Canadian Natural realized a wellhead price of C$6.02/mcf for 2003, up 60 percent from the C$3.76/mcf realized in 2002. The Company's North American sales portfolio of 1,245 mmcf/d is well diversified, with 28 percent of sales directly into various American markets and 87 percent of all prices floating with prevailing market indices.

North American natural gas prices were very strong in 2003, averaging US$5.44/mmbtu for the NYMEX and C$6.70/mmbtu for Alberta pipeline gas, respectively 67 percent and 65 percent stronger than for the previous year.

This 2003 pricing environment supported a very active North American drilling program; however, even with record completions, overall industry production declined from 2002 levels by 3 percent in the US and Canada. Despite industry's 13,963 completions, the WCSB overall production decline rate for 2003 was 25 percent. The first year decline rate was 41 percent for new wells, with initial production rates of only 350 mcf/d, about half of what it was just five years ago. This challenging supply scenario is expected to improve only marginally with continued intense drilling activity in the current year. Industry's 2004 exit rates are currently forecasted to show a further decline of 3 percent in overall North American production.

To meet the rising natural gas demand in the near term will require continued intense drilling activity and a significant increase in the quantities of liquified natural gas imported to the US. The development of coal bed methane in Canada and the construction of pipeline capacity to bring the McKenzie Delta and Alaskan gas to markets will be required over the next decade. This tight supply scenario should result in a strong pricing environment for North American natural gas for many years to come.

Canadian Natural's North American natural gas production for 2004 is forecast to average 1,290 – 1,350 mmcf/d. Based on the current pricing strips for NYMEX natural gas of US$5.13/mmbtu and Alberta natural gas at C$6.01/mmbtu, this would yield an overall wellhead price of C$6.02/mcf for the Company's sales portfolio.

Crude oil

Canadian Natural realized a wellhead price for crude oil and NGLs in 2003 of C$31.59/bbl, up 6 percent from last year. Annual sales increased by 13 percent to average 242.4 mbbl/d and the portfolio mix was 7 percent lighter with 57 percent of the volumes comprised of Pelican Lake and light oil grades.

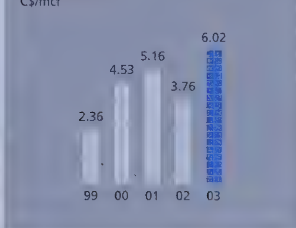
The benchmark prices for crude oil in 2003 were up 19 percent for WTI at US$31.02/bbl and 15 percent for North Sea Brent at US$28.83/bbl, respectively. These price increases were offset by the 11 percent depreciation of the American currency against our Canadian dollar during the year. The 2003 price differential between WTI and a typical Lloyd heavy blend widened by 32 percent to US$8.55/bbl; however, price differentials as a percentage of WTI were 28 percent in 2003 versus 25 percent in 2002, both below the long-term differential ratio of approximately 30 percent.

Daily world crude oil demand increased by 1.4 million barrels in 2003 and is expected to continue growing at the same rate for the next three years. A large portion of this demand is derived from China, currently at 6.1 mmbbl/d, and expected to grow at a rate between 5 and 10 percent annually for the next several years.

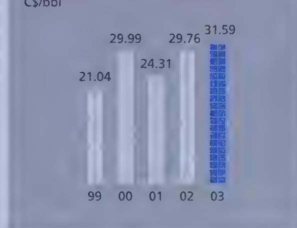
Inventories of crude oil and finished products are at their lowest levels in more than 30 years and the theoretical spare capacity of 2.1 mmbbl/d available from the OPEC producers now represents only 7 percent of their total productive capacity. Large capital expenditures are required to develop additional production and build the logistical infrastructure to reach the markets.

The supply and demand fundamentals are supportive of a robust pricing environment over the next few years. Based on the current pricing strip of US$32.00/bbl for WTI and differentials of US$8.75/bbl for Lloyd blends and US$2.42/bbl for Brent, the Company's portfolio would yield an overall wellhead price of C$30.19/bbl.

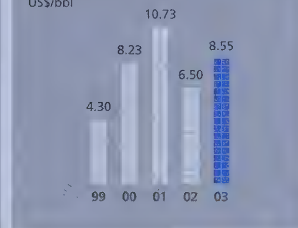
Réal M. Cusson
Senior Vice-President, Marketing



Company average natural gas selling price
C$/mcf



Company average crude oil and NGLs selling price
C$/bbl



Lloyd blend price differential to WTI
US$/bbl

The Company has vast undeveloped heavy oil resources that can be economically developed. The development of these resources is dependent on its ability to find sufficient diluent material to effectively prepare blended heavy oil suitable for transportation by pipeline and on finding additional markets capable of refining such crude oil. Canadian Natural's heavy oil marketing strategy is to extend our geographic reach into new markets and to increase the volumes processed by the existing refineries. To this end, the Company supports various pipeline projects that would extend access to refineries located in the US Gulf Coast area, the West Coast and Asian markets. Similarly, Canadian Natural continues to encourage refiners to add conversion capacity to their existing plants and would consider taking on a more direct role in such projects if appropriate.

Finally, we recently commenced supplying a blend of raw bitumen from our Lloyd areas and sweet synthetic oil from the Fort McMurray area, called Synbit, to a few refineries in the US Midwest. Over time we will be able to adjust the blending ratios based on feedback from our customers, resulting in a product that better meets their input criteria. The objective is to provide refiners with feed stocks comparable to the international medium sour grades they currently process, allowing them to maintain or improve their economics based on the quality and quantities of marketable products they obtain from such Canadian blends. The diversification of supplies from a highly reliable and pipeline connected source is another positive attribute for these refiners.

The Company is also planning on marketing blends consisting of regular diluent and Synbit to further increase the size of the potential heavy oil markets and is leading an industry effort to consolidate various small crude streams into a very large stream. This new western Canadian stream would offer consistent quality that would add value to the refiners while reducing the overall blending and transportation costs for the producers.

Price Risk Management

Canadian Natural utilizes hedging techniques to provide some assurance on price realizations and to protect cash flow generation capability in order to fund ongoing development programs. Generally, we will determine the downside pricing risks associated with various commodities and, if deemed appropriate, will use financial derivatives to establish costless collars to limit risk. Currency exposures are also monitored and may be hedged in conjunction with commodities.

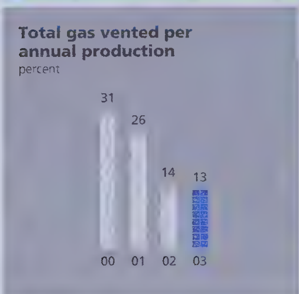
The Company's Board of Directors has granted management the authority to hedge up to 50 percent of any commodity's expected production volumes for a forward twelve month period and up to 25 percent for the second twelve month period. This policy is reviewed by the Board of Directors on a regular basis and may be amended in anticipation of major expenditures associated with the Horizon Project.

Midstream

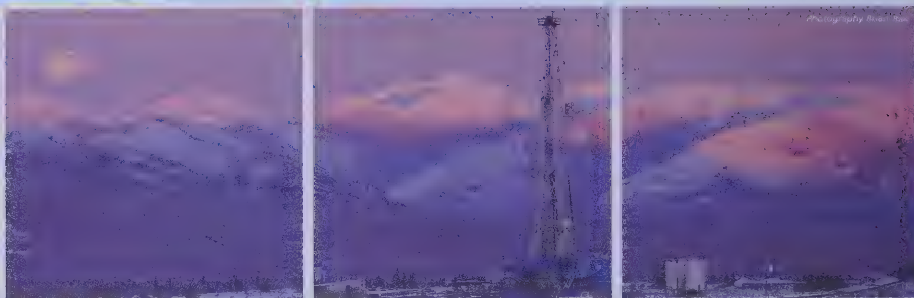
The Company's midstream assets consist of the 100 percent owned and operated ECHO Pipeline, the 15 percent interest in the Cold Lake Pipeline system, the 62 percent interest in the operated Pelican Lake Pipeline and the 50 percent interest in the 84 megawatt co-generation unit located at our Primrose facility. The midstream assets allow the Company to control and optimize its transportation costs for 85 percent of its heavy oil production and generate additional revenues from third party volumes and the sale of surplus electricity.

Additional pumping stations were completed on our ECHO Pipeline in October increasing the daily stream capacity by 24 percent to 72 mbbl/d. We expect to run at full utilization rates for the foreseeable future and forecast a 19 percent reduction in our pipeline unit operating cost for 2004. ECHO is the only pipeline delivering raw bitumen to the Hardisty terminals and plays an important role in our heavy oil blending and marketing strategy for Synbit and other diluted bitumen blends.

Environment, health & safety and community



Solution gas conservation has increased dramatically as a result of a focused program.



Pink Mountain
Located in the Rocky Mountain Foothills of British Columbia, northwest of Fort St. John, Pink Mountain glows a vibrant pink color at sunrise. To reduce our footprint, Canadian Natural utilized directional drilling techniques at an existing previously abandoned site.

Our initiatives and achievements in environment, health and safety, and community in 2003 continue to support both Canadian Natural's defined growth strategy and our commitment to responsible operations. We are focused on continuous improvement in our performance in these areas in order to sustain growth and contribute to the management of an increasingly complex portfolio of assets.

Achieving environmental performance goals

Environmental protection is a fundamental value for Canadian Natural. We integrate environmental planning and management, as well as stakeholder involvement and consultation, from project planning and design to ongoing operations.

We demonstrated our commitment to this approach in numerous ways in 2003. In our Horizon Oil Sands Project, for example, we have devoted substantial efforts during the past years into planning the phased, orderly development of this tremendous resource. At a joint Provincial-Federal public hearing in September 2003, we substantiated how we will develop this resource efficiently, economically and in an environmentally responsible way. In January 2004, the joint panel approved the Horizon Project.

Other highlights in 2003 included:

INTEGRATED AIR EMISSIONS MANAGEMENT

Canadian Natural is committed to managing air emissions through an integrated corporate approach. Through the ongoing involvement of engineering, operations, environmental and regulatory personnel in an Integrated Air Emissions Management Working Group, we plan and implement strategies for such initiatives as gas conservation, greenhouse gas (GHG) emission reduction, and installation of new technologies.

ONGOING REDUCTIONS IN FLARING AND VENTING

Our gas conservation efforts associated with heavy oil production continue to deliver exceptional results. At our Primrose Field in Alberta, a concerted effort during the past two years, and an investment of close to $50 million, have reduced flaring to just 7 percent of what it was in 2001. We are applying our experience from this success at other facilities. Our efforts related to the collection of solution gas are also paying off. While our heavy oil production has significantly increased, so has our solution gas conservation rate – to almost 70 percent in 2003. This compares to less than 5 percent in 1999.

GREENHOUSE GAS (GHG) REDUCTIONS

Our goal is to consistently reduce GHG emissions per unit of production. Canadian Natural's total GHG emissions have decreased by more than 34 percent, with a 36 percent decrease per unit of production on the total sales of hydrocarbon products. In our 2003 GHG Action Plan submitted to Canada's Climate Change Voluntary Challenge and Registry Inc. (VCR), we outlined our plans for continued reductions. Our report was awarded a gold-level reporter status again in 2003.

vcr-mvr Inc. Gold™ Champion Level Reporter

REDUCTION OF FRESH WATER USE

Our Primrose operations are also a prime example of how we are focusing on ways to reduce our fresh groundwater use. By 2009 our plans for Primrose operations target an 85 percent reduction in fresh water use – replacing all fresh water for steaming purposes with brackish water. In 2003 we began the use of brackish water from existing source wells. Meanwhile, engineering is underway on a water treatment plant and on the development of additional brackish source wells. In 2004, two brackish wells will be drilled and a water pipeline installed.

AGGRESSIVE DECOMMISSIONING, ABANDONMENT AND RECLAMATION PROGRAMS

Canadian Natural has a long-term, proactive strategy to manage these responsibilities, reduce our liabilities, and meet all reclamation and decommissioning standards. In 2003, we invested about $40 million into these programs, with $49 million budgeted for 2004.

PIPELINE INTEGRITY PROGRAM

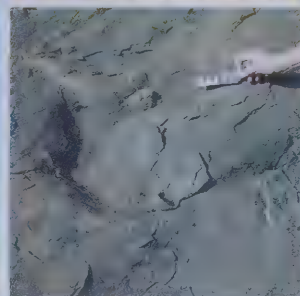
As part of our spill prevention and reclamation initiatives, in 2003 we implemented a new pipeline integrity program that included the addition of seven new corporate and field staff. Through this and other measures, our spill volume by annual production decreased by about 33 percent from 2002 levels.

INTERNATIONAL OPERATIONS WORK TOWARD ISO 14001 STANDARD

CNR International is well advanced in the development and the implementation of an Environmental Management System that meets the requirements of the international standard ISO 14001.

William R. Clapperton
Vice-President, Regulatory, Stakeholder and Environmental Affairs

This is a Baobab Tree from Côte d'Ivoire. The tree is highly regarded by African people because all of its parts can be utilized in some capacity.



During 2003, a 100 million year old Ankylosaur footprint measuring just under one metre in length was discovered near our Tumbler Ridge area in NEBC. We are working with local experts to ensure proper research of the site.

Ensuring a healthy and safe workplace

Canadian Natural conducts operations in a way that protects the health and safety of employees, contractors, the public and the environment.

In early 2004 we will implement our new 15-element Health and Safety Management System, which we continued to develop in 2003 with the input of our operations teams. This system, based upon industry best practices, will help us deliver effective safety programs for our growing operations.

Canadian Natural believes that all employees and contractors need to be actively engaged in ensuring our health, safety and environmental goals are met. Our education, training and awareness programs for employees and contractors help to support continuous improvement and the fostering of best practices. We have also seen excellent results in the timely and effective completion of action plans arising from the continued involvement of operations personnel in our comprehensive audit and inspection programs.

Our international operations team was honored with the Pilkington Alan Poole trophy for Behavior-Based Safety Programs for 2003. This is a national competition attracting 60 entrants from across the UK. The award for our "Murchsafer" program is an outstanding achievement for our workforce.

WORKING CO-OPERATIVELY WITH STAKEHOLDERS

A growing focus during the past few years for Canadian Natural has been on proactive participation and support for multi-stakeholder initiatives that are shaping the policies and future for the oil and gas industry. These initiatives are wide-ranging and include GHG emission reduction strategies, Aboriginal policy development, regional monitoring and research programs, and the development of new legislation. Canadian Natural views our involvement and co-operation in such multi-stakeholder forums as essential – not only in securing the sustainability of our business, but in making a positive contribution to addressing issues facing our industry.

We also continue to make ourselves highly accessible to landowners and the communities where we do business. Through two-way communication and productive working relationships, we are achieving site-specific solutions to address concerns and issues and capitalizing on opportunities to involve stakeholders in the economic opportunities and benefits offered through our operations.

There are more than 50 Aboriginal communities in the vicinity of our Western Canadian operations. We are working to involve these communities in our operations – to open up economic opportunities, to foster community development, and to promote the use of traditional environmental knowledge in our development and reclamation strategies. We are strong proponents of training and education and stay-in-school programs. We also believe in supporting Elders in their goals of retaining their culture and traditions for future generations.

Our Building Futures Training and Education Program is going into its third year. Within the first two years, Canadian Natural has provided scholarships of more than $200,000 for more than 100 Western Canadian students primarily interested in technical and trades education related to the oil and gas industry. More than 30 of these scholarships have gone to Aboriginal students. Our donations and sponsorship programs support a wide range of initiatives that contribute to the improvement of quality of life in the many communities where we do business – in Canada and internationally. In West Africa, for example, we support a range of community initiatives focusing on the provision of medical facilities, community health awareness programs and educational facilities and equipment.

Our employees

Our team has grown dramatically over the last five years, reflecting strong corporate growth.

Lonnie Abadier, Walday Abeda, Hazel Aberdein-Quirie, Michael Adams, Steven Adams, James Agate, Garrisen Ailsby, John Aina, Fiona Aitken, Sina Akinsanya, Brian Akre, Chris Alderson, Andrew Alexander, Gregory Alexander, Sullivan Alexander, Elena Algazina, Jill Allen, John Allen, Simon Allerton, Devin Allibone, Gordon Almond, Jocelyn Alonso, Nelson Alook, Sylvia Anaka, Grayson Andersen, Troy Andersen, Bruce Anderson, Cal Anderson, Greg Anderson, Jeremy Anderson, Kelvin Anderson, Leonard Anderson, Murray Anderson, Perri Anderson, Richard Anderson, Dale Andres, Todd Andrews, Gloria Angeles, Sherley Angers, Kathy Antonishyn, Shelley Antonuk, Jim Archibald, John Argan, Mark Ariss, James Arkley, Darryl Armstrong, Randall Armstrong, Rob Armstrong, Niels Arveschoug, Clifford Atkinson, John Atkinson, Nicole Atkinson, Jason Auch, Bernard Auger, Marianne Auger, Marvin Auger, Richard Augustyn, Niall Avison, Charles Badiou, Cherine Badwi, Dave Baier, Michael Baik, Dwayne Bailer, Chris Baker, Patricia Bakker, Reginald Baldock, Christopher Baldwin, Mark Baldwin, Vaughn Baldwin, Ronnie Ballas, Sheldon Ballas, Darwin Banash, Teresa Banny, Inge Bantli, Tammy Barclay, Garry Bardoel, Larry Bardoel, Nicole Bares, Michael Barnes, Kenneth Barrett, Phrona Lisa Barrett, Melody Barrow, Marty Bartman, Sonia Basati, Lisa Bateman, Kenda Bates, Brenda Battyanie, Veronica Bayley, Colin Beaman, Aura Beattie, Laurier Beaunoyer, David Bechtel, Chris Becker, Ewan Beenham, Robert Befus, Loren Behrens, Guy Belanger, Lesley Belcourt, David Bell, Faye Bell, Jon Bell, William Bell, Reg Bellanger, Shelly Bensmiller, Wes Bensmiller, James Bentley, Linda Beresh, Doris Bergeron, Jeffrey Bergeson, Henry Berlinguette, Allan Bertram, Murray Bertsch, David Biagi, Marc Bickham, Corey Bieber, Douglas Bielech, Inge Biener, Bruce Bignell, Henry Bilodeau, Robert Bilsland, Roger Bintz, Warren Birch, Tim Bird, Travis Bishop, Darwin Bittner, Kevin Bjornstad, Adam Black, David Black, Jennifer Black, Kenneth Blackhall, Kerri Blackmore, Michael Blair, Deana Blais, David Blake, Christopher Blatchly, Ellen Bloomfield, Brad Bodnar, Dennis Boehmer, Michael Boer, Darcy Boettger, Marty Boggust, Brent Boguslaw, Gordon Bohrson, Paul Boileau, Peter Boisvert, Michael Bolianatz, Greg Bolin, Shawn Bond, Peter Bonnell, Marguerite Bonnet, Melanie Booth, Albert Bordeleau, Lynnette Borgland, Michael Born, Jon Borstel, Greg Boshaw, Suzanne Boudignon, Kari Bouillet, Carl Bourque, Daryl Bourque, Jim Bowers, Slade Bowers, Donna Bowles, Dale Boychuk, Jeffrey Boyd, Patrick Boyd, Randy Boyd, Neil Bozak, John Brabec, Bryan Bradley, Peggy Bradner, Jan Bradshaw, Marianne Brady, Mary Jane Brady, Linda Bragg, Eleanor Branagh, Myron Brataschuk, Brad Braun, Colin Brausen, Tara Brechin, Sharon Breitkreuz, Joseph Breland, Paul Breland, Barry Brick, Shawn Brockhoff, Alistair Brockie, Ashley Broderick, Bill Bromling, Murray Brooker, Dennis Brooks, Steve Brown, Robert Brownless, Elizabeth Brownrigg, Gordon Bryant, Gordon Buckshaw, Ryan Bulger, Clarence Bur, Trevor Burchenski, Jeffrey Burdett, Heather Bureau, Keith Bureau, Dave Burger, Grant Burgess, Crystal Burke, J. Rick Burns, Corinne Burton, Bob Butterworth, Ronald Butts, Leanne Butz, Tricia Butz, Todd Bymoen, Mike Byrtus, Irina Byvald, Mark Cadman, James Cadrain, Laura Calder, Leslie Calder, Richard Calliou, Lorraine Cameron, Tyson Cameron, Clayton Campbell, Dean Campbell, Doug Campbell, Robert Campbell, Robert Campbell, Andre Campeau, John Capstick, Fred Cardinal, Harley Cardinal, Sharon Cardinal, Wayne Cardinal, Jim Carey, Ian Carleton, Albert Caron, Rick Carr, Kim Carrol, Gary Case, Mary-Jo Case, Trevor Cassidy, Mike Catley, Samuel Cervantes, Ernest Chachula, Joe Chamberlain, Katrina Chambers, Lise Champagne, Alan Chan, Jik Chan, Sarah Chan, Tim Chan, Alan Chaney, Calvin Chapman, Melody Chapman, Todd Chapman, Deon Chappell, Darryl Charabin, Sabrina Charlton, Cynthia Chartrand, Leon Chateauneuf, Siddique Chaudhry, Dawn Chau-Lam, Mike Chernichen, James Cheung, Patricia Childs, Jamie Chisholm, William Chiverton, Jessica Choi, Raymond Chong, Wayne Chorney, Lynn Chotowetz, Sherry Chow, Jeannie Choy, Alphonse Chretien, Paulette Chris, Ruth Christensen, Marianne Christianson, Steven Christie, Andy Chu, Sharon Chung, Heather Church, Sonja Chycoski, William Clapperton, Andrea Clark, Evan Clark, Mike Clark, Olivia Clarke, Sanja Clarke, Walter Clarkson, Greg Clegg, George Clutton, Dale Coburn, Judith Cochran, Anna Cochrane, Sabrina Colangelo, Martin Cole, Elva Coley, Rod Collins, Roy Collison, Chris Conway, Sean Conway, Brad Cook, Bill Cooke, Kent Cooper, Jean Corbiere, Elaine Coreman, Gordon Cormack, Linda Cormier, Rosetta Cormier, James Corner, Lorenzo Cortes, Neil Cortmann, Neil Costeloe, Wayne Cote, Juan Cottier, Jack Courchene, Kathryn Courtney, Dave Cousins, David Cousins, James Coutts, Gordon Coveney, Keith Cowger, Jonathan Cox, Randy Cox, Nigel Crabb, Harry Crabtree, Layne Craig, Bruce Crain, Bryan Crawford, Trisha Crawford, Beverley Creed, Donald Cretney, Roger Crichton, David Cridland, Stefan Croft-Bednarski, Christopher Cross, Lana Cross, Lloyd Cross, Kirby Crowell, Anthony Csabay, Will Csanyi, Corinna Culler, Arley Currie, Kenneth Cusack, Pat Cusack, Réal Cusson, Ken Cyr, Greg Dacyk, Duane Dahl, Gary Dahl, Layne Dalgetty-Rouse, Walter Danchak, Aniko Dani, Gene Danyluk, Lynne Darlington, Wigo Dascalescu, Graham Davidson, Marie-Louise Davidson, Tim Davidson, Todd Davidson, Graham Davis, Robert Davis, Stephen Davis, Jeffrey Davison, Peter Davison, Leonard Dawe, Robert Day, Ryan De Bruyne, Daphne de Groot, Eric de Kock, Lance de Meillon, David Dean, Harry Dean, William Dean, Parry Debusschere, Derek Dechaine, Raymond Dechaine, Roland Dechesne, Sheldon DeFord, Ian Degiano, Barbara Deglow, Bonnie Deis, Franco Dell'ovo, Benita De Lorenzo, Michael Delorme, Fiona Dempster, Edward Deren, Tom Dereniwski, Travis Desilets, Catherine Desjarlais, Michael Desroches, Laurie Devey, Wendy Devisser, Karen Deyaegher, Aldo Di Flumeri, Harry Diamantopoulos, Sumara Diaz, Daniel Diaz-De-Leon, Cameron Dickson, Sue Didyk, Sandy Diguer, Irene Dikau, Michael Dingley, Gayle 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Farrell, Arthur Faucher, Karman Fayant, Tanya Fayant, Brian Fehr, Darwin Feil, Ira Feland, Kurt Fenrich, Brad Ferguson, Helen Ferguson, Darren Fichter, Alan Fiddes, Michael Filipchuk, Tanya Fir, Calvin Fisher, Rod Fitzpatrick, Sandra Fitzpatrick, Deborah Flanagan, Paul Flanders, Ken Fleck, Sean Fleming, Rodney Flett, Trevor Flood, Edmond Foisy, Justin Foisy, Ryan Folkerts, Hop Chi Fong, Gregory Fontaine, Robert Fontaine, Lynn Foo, Harris Foote, Adele Forcade, Curtis Formanek, Randy Formanek, Devon Fornwald, Alistair Forsyth, Gilles Fortin, Dwayne Fotty, Lise Fournier, Peter Fowler, Donald Fox, Donna Frame, Ron Frank, Gail Fraser, Ken Frazer, Roger Frere, Brad Friesen, Kenneth Friesen, Kevin Frith, Andrei Frizorguer, Susan Froehlich, Frank Frosini, Scott Froude, Karen Fujimoto, Ted Furuya, Josephine Gaddi, Leonard Gadowski, Sharon Gaehring, Kelly Gagne, Scott Gair, Larry Galea, Ron Gall, Michael Gallon, A.William Galloway, Yoko Galvin, Terry Gammel, Jon Gareau, Heather Garness, Maurice 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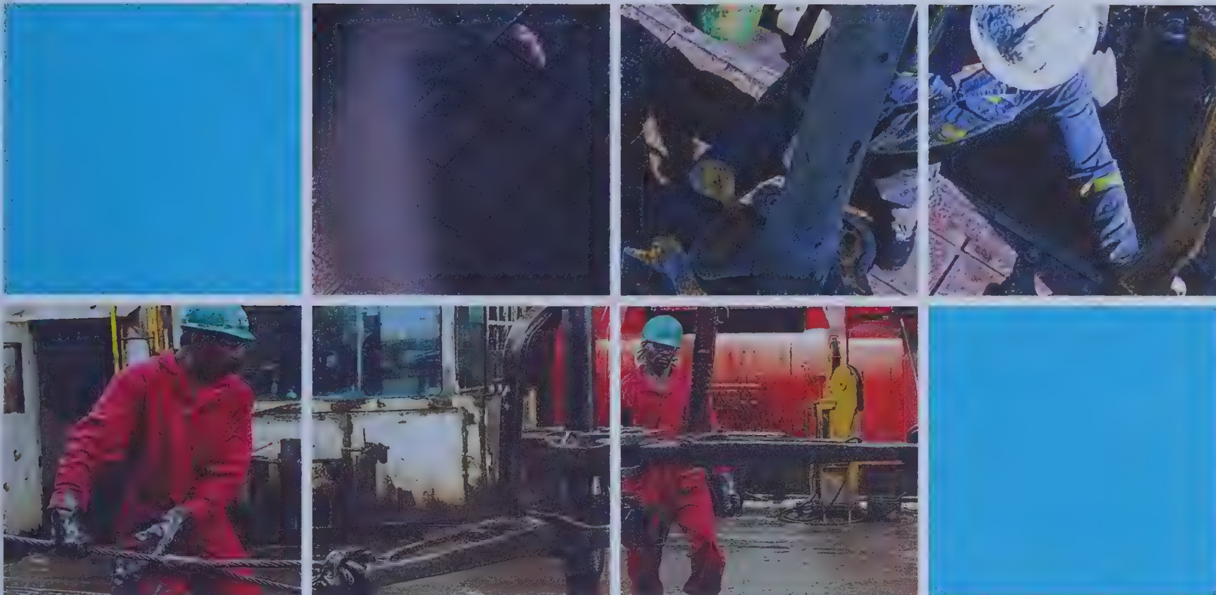

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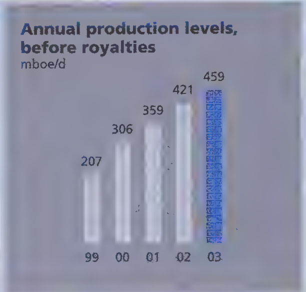
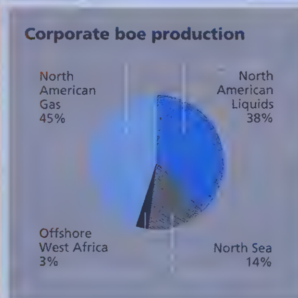
Review of assets

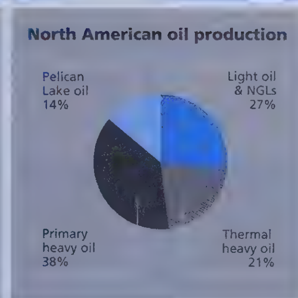
Our philosophy is to dominate production, infrastructure and undeveloped land within our core regions. This creates a low-cost growth platform based upon exploration, exploitation and strategic acquisitions.



Tim S. McKay
Senior Vice-President,
North American Operations



A balanced production mix reduces sole commodity price risk.



North American liquids production is a balance of various grades of crude oil and NGLs.

Canadian Natural focuses on five core regions in western Canada and has international operations that are concentrated in offshore environments in the North and Central portions of UK North Sea as well as Côte d'Ivoire and Angola in Offshore West Africa. Canadian Natural believes that keeping a strong prospect inventory in each of its products and basins is essential to provide the flexibility to develop assets in a manner that achieves superior returns. The Company's development and exploration project inventory and its product diversity creates near-, mid- and long-term growth opportunities.

The Company controls its development activities and costs by maintaining operatorship and maximizing working interests. Low operating costs are achieved through owning and operating the infrastructure, maximizing facility utilization and having a large land base that supplies additional development opportunities.

Capital is minimized due to the scale of the Company's operations, through optimal project scheduling and by controlling the pace of development.

Internationally, Canadian Natural employs the identical philosophy developed for western Canada. Specifically, the goal is to operate, maximize working interests and control the development of the Company's projects. The Company develops assets in new areas at a modest pace until sufficient expertise and competence is gained to allow it to maximize the profitability of that area.

Natural gas – core region summary

	Northeast British Columbia	Northwest Alberta	North Alberta	South Alberta	Other
Average production (mmcf/d)					
2002	451	171	420	146	44
2003	**372**	**261**	**462**	**142**	**62**
Natural gas facilities, operated	74	29	97	61	–

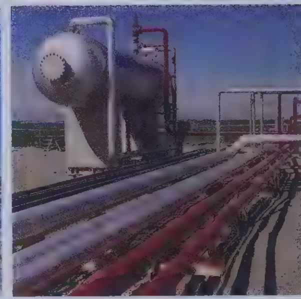
North American crude oil and NGLs – core region summary

	Northeast British Columbia	Northwest Alberta	North Alberta	South Alberta	Southeast Saskatchewan	Other
Average production (mbbl/d)						
2002	7	7	136	9	9	1
2003	**7**	**11**	**136**	**11**	**9**	**1**
Crude oil facilities, operated	8	8	23	34	35	–

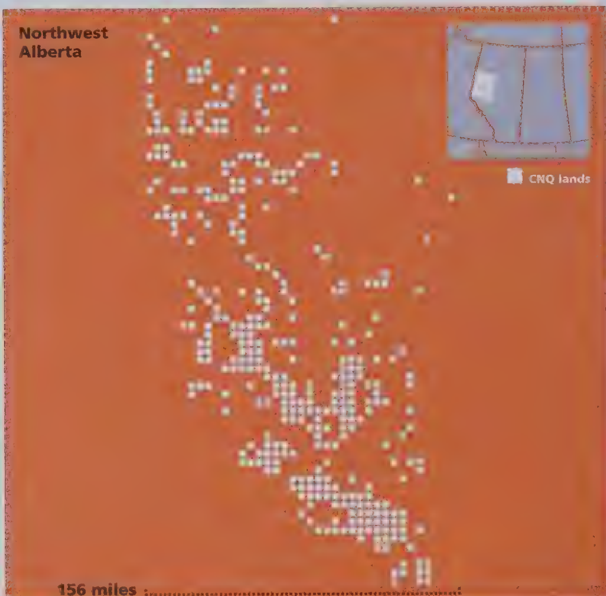
International crude oil – core region summary

	Offshore West Africa	North Sea
Production (mbbl/d)		
2002	7	39
2003	**10**	**57**
Platforms/FPSOs, operated	1	5

North American Natural Gas



Natural gas is Canadian Natural's single largest product, representing 47 percent of sales volumes and 51 percent of sales revenues. During 2003, average production volumes increased by 5 percent, reflecting an increase in the drilling program and the mid-2002 acquisition of Rio Alto Exploration Ltd. The Company's current natural gas production is concentrated in four of its North American core regions: Northeast British Columbia, Northwest Alberta, North Alberta and South Alberta.



Northwest Alberta

This region contains exceptional exploration and exploitation opportunities as well as substantial available capacity within an extensive, owned and operated infrastructure. Canadian Natural produces liquids rich natural gas from multiple, often technically complex horizons, with formation depths ranging from 3,000 to 15,000 feet. Canadian Natural's goal for 2003 was to understand the Cardium play in a way that would facilitate greater success at lower cost and to balance exploitation of the Cardium against all other prospective formations in the region. During 2003 a multi-disciplinary team of professionals was created to improve our understanding of the Cardium play. The team was also tasked to drive individual drilling costs down. This team has managed to complete a very extensive regional geological study and drop drilling costs by about 50 percent. During 2004 a team similar to that established for the Cardium target will be formed to seek out Cadomin play opportunities. The Cadomin is also a complex tight sand similar in many respects to Cardium, but deeper.

North Alberta

Natural gas in the North Alberta core region is produced from shallow, low risk, multi-zone prospects and represents about 40 percent of the Company's natural gas production. This is a mature operating region; however, through development drilling recompletions and optimized operations, it continues to be one of the best cashflow generating regions in the Company. As a mature basin, a key to success is to maintain high utilization of infrastructure and control capital through effective drilling and recompletion planning. To this end, the Company's strategy is to dominate its vast land base and target exploration and synergistic property acquisitions to maintain high utilization. The Company's five year plan calls for annual region production declines of only 6 percent against typical well declines of 23 percent per annum.

An example of the Company's strategy is Jean Lake, in northern Alberta, where assets were acquired in 2001. Between exploitation drilling of these lands and the acquisition of additional crown leases, the Company has doubled production levels.

Jeffrey W. Wilson
Vice-President, Exploration,
BC/S.AB Districts

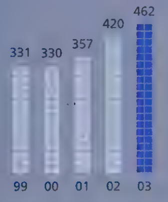
The area is expected to grow production at over 15 percent per annum over the next 5 years. Infrastructure in the region is underutilized which will facilitate cost advantages compared to competitors. The land base Rio Alto had accumulated was high quality and majority owned.

Annual production
mmcf/d

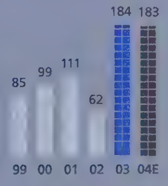
Successful wells drilled
excludes stratigraphic test/service wells

North Alberta remains a core exploitation area where we are able to leverage our infrastructure to add new production at low-cost.

Annual production
mmcf/d



Successful wells drilled
excludes stratigraphic test/service wells



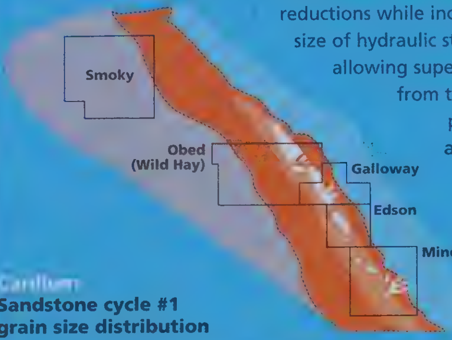
Case study Northwest Alberta Cardium

During 2003, Canadian Natural completed comprehensive geological, geophysical and engineering studies in order to better understand the Cardium play; a regionally extensive, tight reservoir sand where high natural gas productivity (1-10 mmcf/d) can be achieved in areas of greater matrix porosity and/or natural fracturing. The study covered 45 townships (4,200 km^2) in the Edson-Smoky area. Well logs, cores and drill cuttings from over 1,000 wellbores were examined for sand thickness, depositional facies, grain size and reservoir parameters. Trend maps of regional sand units help quantify and predict matrix porosity and permeability and identify areas of potential high gas reserves.

3-D seismic is used to locate "sweet spots" where faulting and fracturing will allow the gas to be produced at commercial rates. Vertical wells may access open fractures in both the hanging and footwall as well as stacked Cardium structures. The Company now believes that vertical wells are the optimum method of exploiting gas reserves in the Cardium.

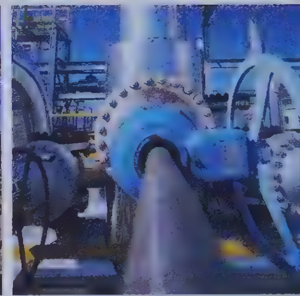
In addition, "best practice" engineering studies and the application of innovative drilling and completion techniques achieved significant onstream cost reductions of up to 50 percent. For example, water-based rather than oil-based drilling mud significantly reduced costs, the use of new drilling bits allowed wells to be drilled faster, and well design was improved to avoid expensive re-drills or sidetracks. Finally, completion designs were simplified to allow faster completion of hangingwall and footwall sands.

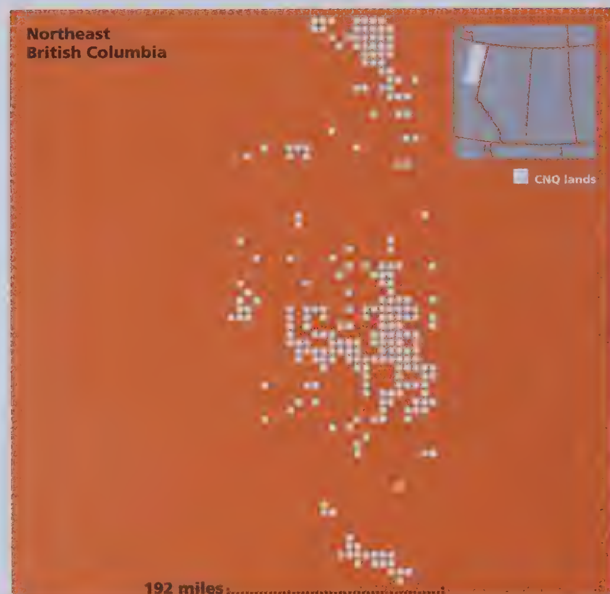
The studies have facilitated cost reductions while increasing the size of hydraulic stimulations, allowing superior returns from the Cardium play in 2004 and beyond.



Cardium
Sandstone cycle #1 grain size distribution

North American Natural Gas (continued)





Northeast British Columbia

The Company's experience in the province, its large undeveloped land base and existing infrastructure affords a significant competitive advantage in the highly prospective region of Northeast British Columbia. Canadian Natural has significant production, infrastructure and undeveloped lands in three distinct areas.

Most northerly is the Helmet area, where the Company employs horizontal wells to exploit the low risk, regionally extensive, natural gas charged Jean Marie carbonate formation. Natural gas is produced in the Fort St. John area from an array of carbonate and sandstone reservoirs. Most southerly is the Foothills area where the Company targets deeper Mississippian and Triassic age reservoirs in this highly deformed structural area.

At Helmet, the Company drilled 35 wells with an 94 percent success rate that added 90 bcf of new reserves and grew production by 40 mmcf/d. For 2004, a further 52 such wells are planned.

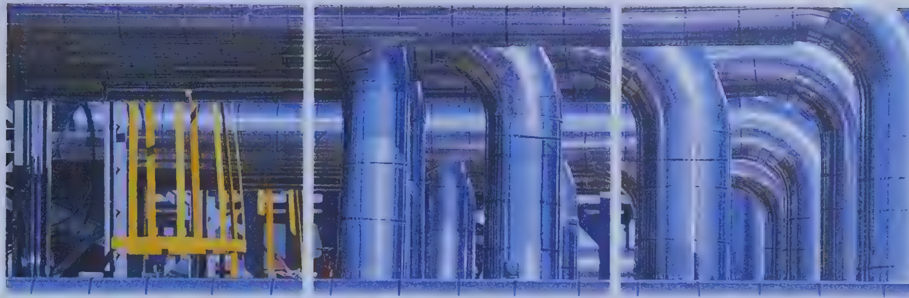
South Alberta

Natural gas in the South Alberta core region is produced from shallow, low risk, multi-zone prospects. Canadian Natural has been in this core region since 1996, growing its production by an average 6 percent per annum. While production per well is lowest of any of the core regions, drilling costs remain under $200 thousand per well and the annual production declines are the lowest at 18 percent.

The key to success in this region is to utilize area dominance to add low cost volumes. This includes keeping a large inventory of drillable prospects. The Company estimates that the current landbase will afford in excess of 2,300 drillable locations over time. The knowledge gained from shallow drilling operations has been utilized in Northeast British Columbia for the commercial development of the Notikewin play.

The 2003 drilling program, at 430 wells, was the largest in the Company's history and it resulted in volume growth of 8 percent. During the year, Canadian Natural also discovered a new shallow gas play at Etzikom, which is now in development.

Cameron S. Kramer
Vice-President, Field Operations

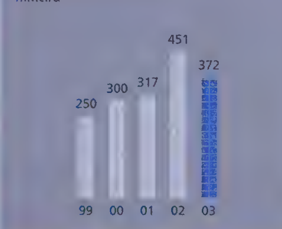


With respect to Slave Point exploration, while the Company believes that the likelihood of discovering another pool the size of Ladyfern is remote, it will apportion a small capital budget to exploring 2-3 pinnacle reefs per year with target sizes of 10 to 30 bcf. During 2003, the Company utilized its expertise in shallow gas drilling to develop a new program targeting the Notikewin formation in the Fort St. John area. For years, Canadian Natural and other companies have drilled through this shallow zone while targeting deeper zones and noticed small amounts of natural gas. The Company looked at this opportunity in combination with its extensive land base and the recently reduced royalty rates in British Columbia and developed an extensive play that will add 450 new drilling locations over the next five years. These wells cost about $150 thousand each and produce at rates of 500 to 700 mcf/d.

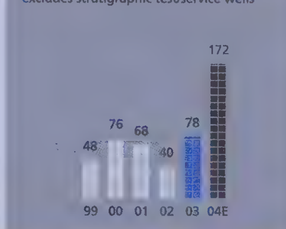
In the Foothills area the Company is increasing its focus in a measured way. Well costs are higher and pipeline infrastructure can be limited but rates and reserves, if successful, are typically higher. In 2004, two deep wells are planned.

Northeast British Columbia is a multi-zoned, prolific under-drilled portion of the WCSB where we have a large undeveloped land base.

Annual production
mmcf/d



Successful wells drilled
excludes stratigraphic test/service wells

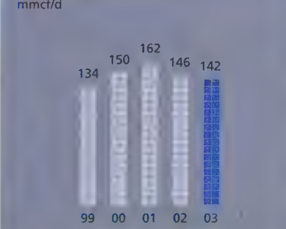


We also managed a significant expansion of our operated infrastructure and land base, largely via property acquisitions at Craigmyle and Enchant. This alone has added 40 new wells into our drilling inventory.

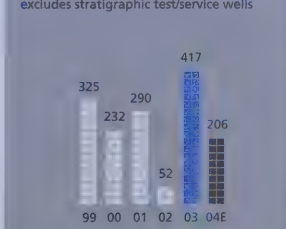
In South Alberta, Canadian Natural has defined exploration and development prospects that will translate into a sustained 6 percent average growth rate for the next five years, with targeted drilling of 400 wells per year. We continue to acquire and consolidate properties in our areas. Beyond this, downspaced drilling provides the ability to accelerate the recovery of the reserves and ultimately increase the value of the assets. Finally, coal bed methane ("CBM") may be a long term production driver in this region and the Company has, in 2004, dedicated a small capital budget of approximately $10 million to this project. The Company, as a major landholder in the WCSB, believes there will be CBM opportunities on its lands; however, in keeping with its approach, will follow a measured "lead the followers" strategy.

In this mature basin, our key strength is continued cost control. This is done through efficient utilization of existing facilities, flexible and fit-for-purpose infrastructure design, consolidation where appropriate, and effective planning of activity to create economies of scale.

Annual production
mmcf/d

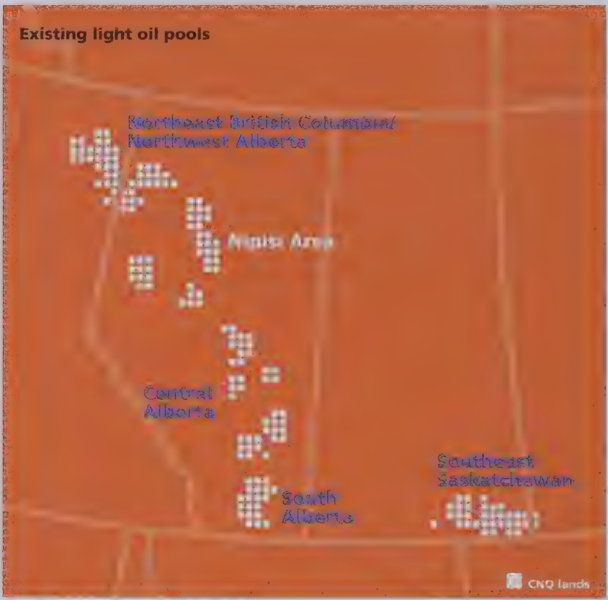


Successful wells drilled
excludes stratigraphic test/service wells



North American Liquids

Canadian Natural is one of Canada's largest producers of crude oil and NGLs with an extensive developed and undeveloped light and heavy oil asset base augmented by NGLs which are produced in conjunction with natural gas. During 2003, average production volumes increased by 3 percent, reflecting a significant drilling and development program. The Company's heavy oil production is concentrated in its North Alberta core region with light oil being produced in all five core areas: Northeast British Columbia, Northwest Alberta, North Alberta, South Alberta and Southeast Saskatchewan.



Light oil and NGLs

Canadian Natural produces light oil and NGLs in all of the Company's western Canadian core regions. NGL production totals 40 percent of Canadian Natural's light oil and NGL production and is concentrated in the liquids rich region of Northwest Alberta.

In North America the Company's light oil assets are largely developed. Canadian Natural continues to grow light oil production through a combination of acquisitions, waterflood optimization and development drilling. Many of the Company's pools are produced under waterflood, resulting in significantly higher recovery factors and lower production decline rates. Canadian Natural has chosen to focus on improvements in waterflood efficiencies since with the Company's large asset base, a 1 percent improvement in recovery could yield an incremental 42 million barrels of oil. Canadian Natural focuses on waterflood optimization through detailed reservoir characterization, analysis of pattern performance, improved well operating practices and improved fluid processing at the surface.

Pelican Lake oil

This large, shallow oil pool in Canadian Natural's North Alberta core region has been developed exclusively with horizontal wells. This technology minimizes surface disturbance and environmental impact, reduces development costs and results in significantly greater well productivity in comparison to alternate techniques. Canadian Natural owns and operates more than 650 horizontal wells and three centralized treating facilities in the area. Although priced similarly to heavy oil, Canadian Natural's Pelican Lake oil production yields netbacks typical of medium oil due to the low operating costs and the favourable oilsand royalty rates. The Company continues to pursue the primary drilling opportunities but will reach the limits of its prospective acreage in the near future. While the Company is forecasting a 5 percent recovery factor from primary production, the developed reservoir on Canadian Natural's leases contains approximately 3 billion barrels of oil in place, making it very attractive for secondary or tertiary recovery.

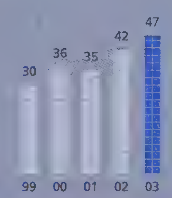
J. Kevin Stromquist
Vice-President, Exploration,
Northwest Alberta

In 2003, the Company created a team of experienced professionals to thoroughly analyze the performance of all the existing waterfloods and to evaluate the implementation of new waterflood projects. This team will also evaluate the implementation of tertiary recovery techniques on select oil pools in an attempt to further enhance recovery efficiencies.

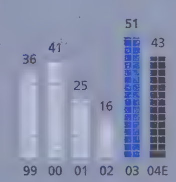
In 2004, Canadian Natural's light oil drilling program has two thrusts: low risk, infill drilling in waterfloods located in the North Alberta and Southeast Saskatchewan core regions and step-out drilling in existing pools in South Alberta and Southeast Saskatchewan.

Our WCSB light oil strategy utilizes the mature pool expertise that we have developed on a world-wide basis.

Annual production
mbbl/d



Successful wells drilled
excludes stratigraphic test/service wells



In pursuit of these incremental reserves, Canadian Natural will begin the phased roll out of a waterflood with approximately 20 percent of the field being under waterflood by the end of 2004. The waterflood will stabilize production and will require a further 63 Pelican Lake productive wells to be converted from producer to water injectors and approximately 43 new wells to be drilled in 2004 as producers.

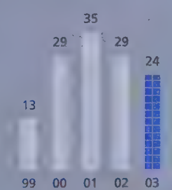
The first commercial phase implementation will encompass approximately 20 percent of the developed portion of the pool and is expected to double primary recovery factors. Future phases in subsequent years are planned to extend the waterflood to remaining developed portions of the field.

During 2003, the Company attempted to increase recovery beyond that expected of a waterflood through testing of an emulsion flood. During a one-year trial, it was determined that although the oil was being effectively swept, the process was uneconomic.

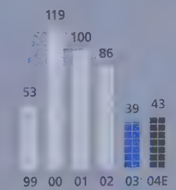
The Company is now examining the opportunity to use these findings in conjunction with waterflood – that is, follow-up waterflood breakthrough with emulsion to optimize response time and sweep efficiency.

Further laboratory and pilot projects to test other EOR techniques are also being examined.

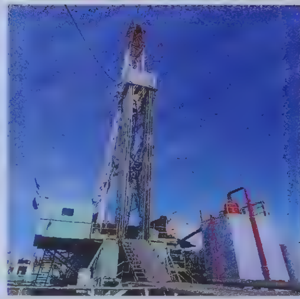
Annual production
mbbl/d

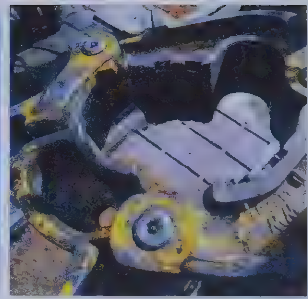


Successful wells drilled
excludes stratigraphic test/service wells



North American Liquids (continued)





Conventional heavy oil

Canadian Natural is one of the largest heavy oil producers in North America. The Company's growth of heavy oil production has been achieved through drilling, as well as strategic, synergistic acquisitions. Canadian Natural dominates production and operations within the Bonnyville primary producing area in the North Alberta core region. This dominance allows the Company to minimize capital by conducting large scale drilling and development programs. Operating costs are also minimized by owning and operating central treating facilities and maximizing their utilization.

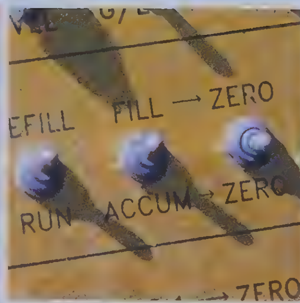
Heavy oil in the Company's North Alberta core region is produced using primary production mechanisms from shallow, low-risk, multi-zone horizons. This leads to low finding and development costs, exceptional drilling success rates and many subsequent recompletion opportunities. The region is also natural gas prone and frequently heavy oil development drilling will lead to synergistic shallow natural gas pool discoveries which can be quickly be tied into the Company's vast infrastructure.

Thermal heavy oil

Canadian Natural is the second largest producer of oil recovered by thermal processes in Canada employing two processes: Cyclic Steam Stimulation ("CSS"), and Steam Assisted Gravity Drainage, ("SAGD"). The Company currently operates three thermal projects: the large commercial CSS project at Primrose, the Tangleflags SAGD project, and the Burnt Lake SAGD pilot project.

Canadian Natural's near term focus is the expansion of the Primrose thermal project at Cold Lake where current infrastructure consists of a steam cogeneration plant, oil and water processing facilities and over 350 active horizontal wells. The year 2003 was a significant milestone for Canadian Natural's Primrose thermal project as the Company commenced development drilling on additional acreage as a result of receiving regulatory approval in mid 2002. This development continues in 2004 with the expansion and de-bottlenecking of the Primrose facilities. Start-up of the expanded facility is forecast for late 2005 with throughput estimated at 80 mbbl/d.

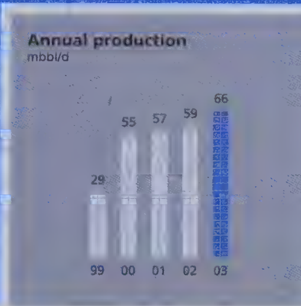
Gordon M. Coveney
Vice-President, Exploration,
Northeast District

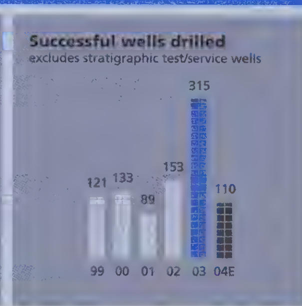


We also leverage our heavy oil ECHO Pipeline to further reduce costs. ECHO is the only pipeline delivering raw bitumen to the Hardisty terminals, playing a significant role in our Synbit strategy.

In early 2004, Canadian Natural acquired additional properties adjacent to its core areas for a cost of $467 million. Through synergistic use of facilities and infrastructure, the Company believes it will be able to drop operating costs by approximately 10 percent. This ability, combined with the 400 new drilling locations and 400 recompletion opportunities, exemplify the type of value creating acquisitions that the Company targets.

We are a leader in heavy oil production from the WCSB. Our size leads to economies of scale that help to keep us a low-cost producer.

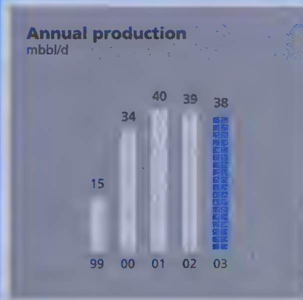


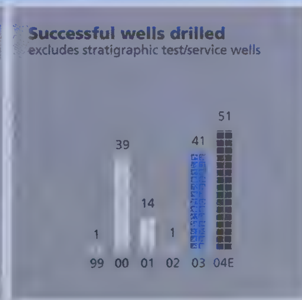


In 2004 the Company will continue with the drilling program that commenced in early 2003 and is forecasting to drill 51 additional horizontal wells in 2004. These wells will be utilized to fill the existing facility capacity and to fill the expanded facility. Optimization of the Primrose facilities combined with low risk development drilling will create one of the most economic in-situ developments in Canada. Production from the Primrose area is forecast to double by 2006.

Mid-term growth will come from the commercial development of Canadian Natural's Burnt Lake project adjacent to Primrose. In the long term the Company will focus on the development of its massive oil sands leases in the Athabasca regions of North Alberta. Canadian Natural holds large leases in the Horizon and Gregoire Lake regions. At Horizon where the oil sands are too deep to mine, a 70 mbbl/d SAGD project is envisioned with potential startup by 2012. At Gregoire there are four industry projects planned or operating adjacent to the Company's leases. In 2004, Canadian Natural will continue with delineation drilling on these leases to aid in defining their thermal development potential.

The Company's operating thermal projects continue to provide economic, geologically proven, low-risk production growth. Canadian Natural's large inventory of prospective, undeveloped oil sands leases will provide growth over the next two decades.





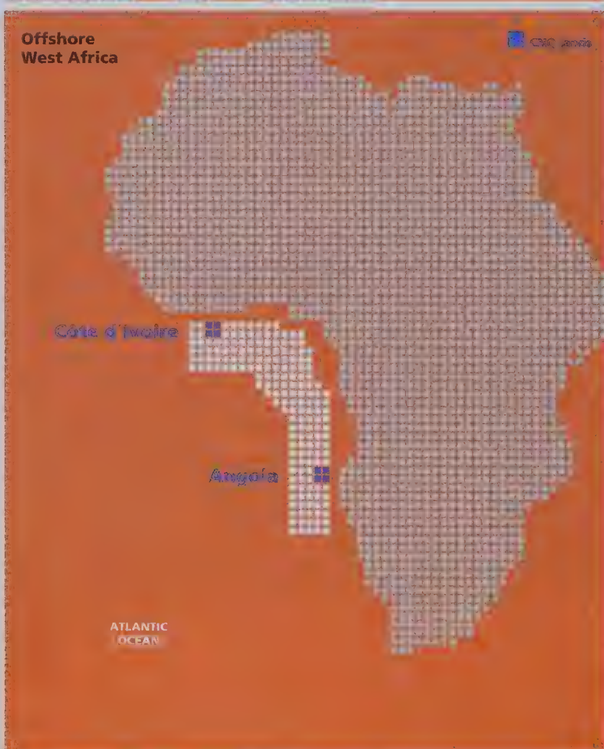
International Light Oil

Canadian Natural views its international operations as the vehicle for continued light oil production growth. At the same time, a disciplined focused approach is considered essential to successful value creation in the international arena and therefore the Company contains its exposure to those basins where it sees the greatest opportunities. The Company capitalizes on its core competency of exploitation in the North Sea where the business parallels that in North America in many key ways. Offshore West Africa provides significant exploration upside and capitalizes on strong government relationships developed by Canadian Natural. The Company believes that it has competitive advantages over other independent producers in gaining access to these basins.

North Sea

Following acquisitions of additional properties in 2002 and early 2003, Canadian Natural operates approximately 99 percent of its production with an average ownership interest of 80 percent. By gaining control of these assets Canadian Natural has been able to accelerate its exploitation plans for the properties. This includes enhanced waterflood management, infill drilling opportunities and targeted near-pool exploration. To this end, the Company spent the first half of 2003 upgrading maintenance programs and improving water injection systems on its four platforms in the Northern North Sea. Production declines from these platforms were arrested and actually reversed in the latter half of the year through implementation of these exploitation and drilling programs.

The Company has also successfully acquired new exploration lands surrounding its infrastructure which will provide near-pool exploration upside. Even smaller pools become economic through the increased utilization of facilities and may extend overall field lives, further postponing abandonments.

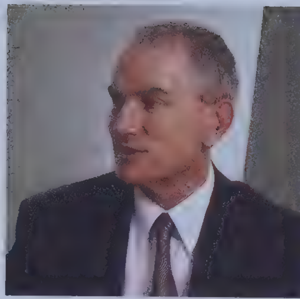


Offshore West Africa

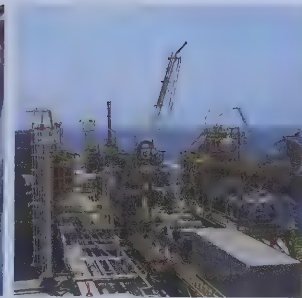
Côte d'Ivoire

Canadian Natural has three exploration Blocks comprising approximately 460 thousand gross acres of land located offshore this West African nation. During 2003, the Company completed its first development project, the East Espoir waterflood, with production having stabilized at 12,000 to 13,000 barrels per day during the fourth quarter and finalized its plans for West Espoir development. Its third and largest development project in West Africa, Baobab, is currently progressing with fabrication of the FPSO and development drilling both having commenced during the fourth quarter of 2003. Production from this project is scheduled to commence at approximately 24 mbbl/d in mid-2005, eventually ramping up to approximately 35 mbbl/d. Near pool exploration activities will continue to be pursued in order to add additional reserves at low cost, taking advantage of existing infrastructure. During 2003, Canadian Natural drilled the satellite pool Acajou. Although the reservoir quality was good and oil was found, it was not of sufficient quantity to warrant tie-back to the Espoir FPSO. However, further review of the geology of the structure indicates that this structure may extend across a sub-sea canyon. The Company continues to evaluate this opportunity as a potential satellite pool development. Approximately 10 million barrels of new reserves would be required to warrant development of the satellite pool. Acajou continues to look prospective as a potential satellite development and a second well will be drilled in 2004.

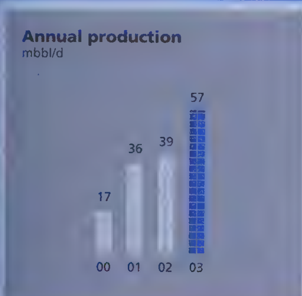
Allen M. Knight
Senior Vice-President, International and Corporate Development

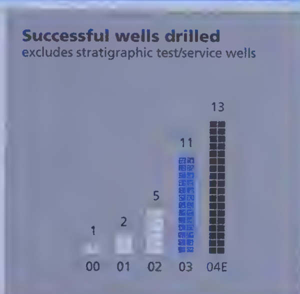


Martin Cole
Vice-President & Managing Director CNR International



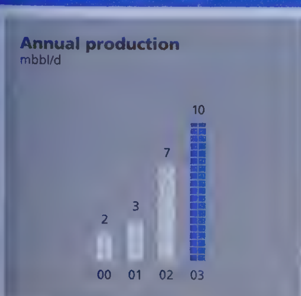
Canadian Natural believes that the current environment within the North Sea is similar to that of western Canada in the early 1990s. The basin is mature and many of the major operators are reducing activity levels or looking at divestiture of properties. Exploitation oriented companies like Canadian Natural are proactively pursuing such opportunities. Should such exploitation opportunities fill, Canadian Natural could continue to grow its North Sea production levels. Absent these opportunities, production levels should remain.

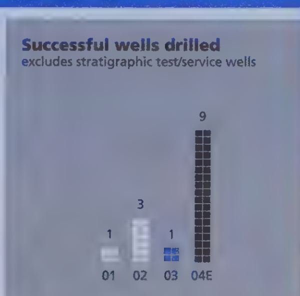




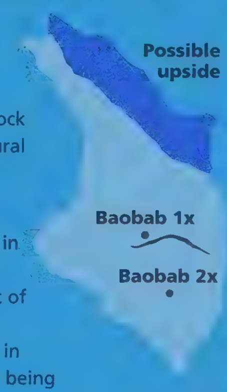
Angola

Canadian Natural has an excellent relationship with the Government of Angola and its national oil company, Sonangol. This relationship and a solid operating history within Angola resulted in Canadian Natural being awarded operatorship and a 50 percent working interest in offshore Block 16. The Company obtained 3-D seismic over the entire Block 16 prior to obtaining title and drilled the first of its prospects, Zenza, during the fourth quarter of 2003 with no commercial quantities of hydrocarbons being encountered. Canadian Natural will integrate new information gathered during the Zenza drill in order to select the best exploration drilling target, expected to be drilled in early 2005.





Case study Baobab



The deepwater Baobab Field was discovered by Canadian Natural in early 2001. The field is situated in Block CI-40, adjacent to the Canadian Natural operated Espoir Field, 27 km off the coast of Côte d'Ivoire.

Following a successful appraisal well in 2002, Canadian Natural opted for an aggressive schedule for development of the field. Baobab extends beneath a north-south trending seabed canyon in 3,500 to 5,200 ft water depths and is being developed with two sets of two subsea well clusters on either side of the canyon that will be tied back to a FPSO with storage capacity of two million barrels of oil. Associated gas will be piped to shore via shared infrastructure with the block CI-26 Espoir Field.

The US$570 million project received sanction in mid 2003. All major contracts for the development of Baobab have been awarded. The FPSO is currently being fitted-out in Singapore. Drilling of the eight producers and three water injector wells commenced in late 2003. Canadian Natural anticipates first oil in the second quarter of 2005 with its share of initial production at approximately 24 mbbl/d, increasing to 35 mbbl/d by 2006. Canadian Natural has a 57.61 percent equity interest in this property.

Horizon Oil Sands Project

Canadian Natural owns a 100 percent working interest in 116,595 acres in the Athabasca Oil Sands area of Northern Alberta, about 70 km north of Fort McMurray. The Horizon Oil Sands Project includes surface oil sands mining, bitumen extraction, bitumen upgrading to produce a 34-36° API SCO, and associated infrastructure.

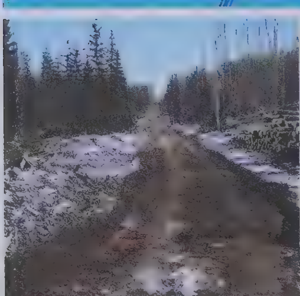
The project is designed as a phased development. Phase 1 production is planned to begin in the fourth quarter of 2008 at 110,000 bbl/d of SCO. Phase 2 would increase production to 155,000 bbl/d SCO in 2010. Phase 3 would further increase production to 232,000 bbl/d SCO in 2012. The phased approach provides the Company with improved cost and project controls in terms of labour and materials management and directionally mitigates the effects of growth on local infrastructure.

Total expected capital costs of the phased development are C$8.0 billion to C$8.5 billion, of which approximately C$5.0 billion would be required for Phase 1. These costs are consistent with final cost estimates for other recent oil sands mining projects. When the Horizon Project is fully commissioned, operating costs, including sustaining capital, are expected to be in the range of C$9 to C$11 per barrel. Current product pricing, capital and operating cost estimates for the project show an internal rate of return between 14 percent and 22 percent based upon long-term average WTI assumptions of US$18 to US$26 per barrel.

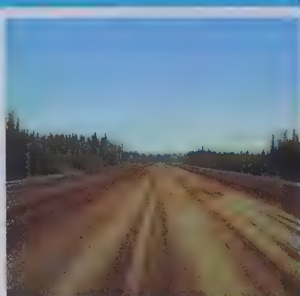
Based upon stratigraphic drilling to date, the Company believes there are approximately 16 billion barrels of bitumen in place on the Company's Athabasca Oil Sands Leases, with approximately 6 billion barrels being recoverable under existing technologies. Additional surface mining and in situ potential exists on the leases. No resources from these leases are included in the Company's current reserves.

Regulatory

Canadian Natural filed an application for regulatory approval of the Horizon Project in June 2002. The application included a comprehensive environmental impact assessment and a social and economic assessment and was accompanied by public consultation. A federal-provincial regulatory Joint Review Panel examined the project at a public hearing in September 2003. The Panel issued its decision report in January 2004, finding that the Horizon Project is in the public interest. The Panel also concluded that the project is unlikely to result in significant environmental effects, provided the mitigation measures proposed by Canadian Natural and the recommendations of the Panel are implemented. Accordingly, the Panel under its mandate through the Alberta Utilities and Energy Board is prepared, subject to the approval of the Lieutenant Governor (of Alberta) in Council to approve the application.



February 2003
Initial site work at new 22 km access road to the Horizon Project.



October 2003
Construction essentially complete, including three river spans. Road was completed ahead of schedule and under budget.

Réal J.H. Doucet
Senior Vice-President, Oil Sands

León Miura
Vice-President, Upgrading

Lynn M. Zeidler
Vice-President, Bitumen Production

The approval will be subject to specified conditions and subject to the Company meeting all commitments made during the application proceedings. The approval (Order-in-Council approval) is expected in March 2004. Other key approvals under the Alberta Environmental Protection and Enhancement Act, the Alberta Water Act and the Federal Fisheries Act are expected to follow in spring, 2004.

Kyoto Protocol

Due to uncertainties about the long term cost implications of the Government of Canada climate change policies, Canadian Natural, along with other major energy project proponents and the Canadian Association of Petroleum Producers ("CAPP"), actively sought greater clarity from the federal government about the long term climate change policy framework. Of particular concern was the period beyond 2012 when policies will be derived from Canada's negotiations for a second Kyoto implementation phase. The government acknowledged the concerns of major projects proponents in a July 23, 2003 letter from the Prime Minister to the Chairman of CAPP. Attached to the Prime Minister's letter was a list of eight guiding principles that will guide the Government of Canada's longer term climate change policies. These addressed the key concerns with regard to equitability, efficiency, flexibility and competitiveness issues for the post 2012 period.

With these commitments from the Government of Canada, Canadian Natural affirmed its intention to construct an on-site upgrader for the Horizon Project.

Design Approach

Canadian Natural is using a structured system called Front End Loading to ensure that project definition is adequate and complete before proceeding with implementation. This system is successfully used worldwide to mitigate risk on large capital projects in a variety of industries. The process is well documented and is audited by an independent organization.

In June 2002, Canadian Natural commenced the Design Basis Memorandum (DBM), which is the second of three front-end engineering phases. Just prior to year-end 2003, the Company commenced work on the third front-end engineering phase, Engineering Design Specifications ("EDS"). When the EDS phase is completed in September 2004, engineering will provide sufficient definition for a lump-sum inquiry for the detailed Engineering, Procurement and Construction ("EPC") of the various project components.

The EDS will also produce a detailed cost estimate (plus or minus 10 percent), and provide the basis of final corporate approval to proceed with the project.

Horizon is designed to use proven technology and will seek to take advantage of technology improvements that advance environmental performance, enhance the work environment, increase reliability and production and reduce capital and operating costs through the EDS and subsequent engineering and operating phases. By the end of 2003, the Company had acquired or entered into negotiations to acquire all key technologies for the project.

2003 developments and 2004 outlook

During 2003, Canadian Natural drilled 345 stratigraphic test wells to further delineate the ore body and confirm the quality of the body. The Company now has an average of 16 stratigraphic wells per section, giving a high degree of confidence of the nature of the ore body. Additionally, required new road infrastructure to the site was completed, including three river spans.

In addition to working together with various government agencies for approval of the plant, Canadian Natural also continued with stakeholder consultation and entered into socio-economic agreements with Aboriginal groups.

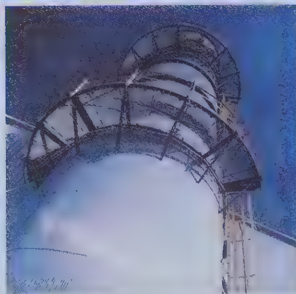
In 2004, the Company has commenced site clearing and preconstruction site preparation activities and plans to complete its DBM by early spring. Remaining major regulatory approvals should also have been received at this time.

In late spring the Company will file applications for power connections, cogeneration and industrial designations.

Following receipt of various EPC quotes and completion of the EDS planning which will provide detailed capital estimates and cost certainty, a corporate decision to proceed with construction of the project will be made. This decision will also be predicated upon a firm financial plan to facilitate development. The principles of this financial plan will maximize ownership levels while maintaining strong credit ratings and while not diluting existing shareholders. This financial plan may include the use of business partners (financiers, builders and/or operators of plant infrastructure, with no interest in the SCO output) or project equity partners.

Management's discussion & analysis

Canadian Natural Resources Limited is a Canadian based senior independent energy company engaged in the acquisition, exploration, development, production, marketing and sale of oil and natural gas. The Company initiates, operates and maintains a large working interest in a majority of the prospects in which it participates. The Company's principal core areas of oil and natural gas operations are in the Western Canadian Sedimentary Basin, the United Kingdom sector of the North Sea and Offshore West Africa.



Special note regarding forward-looking statements

Certain statements in this document or documents incorporated herein by reference for Canadian Natural Resources Limited (the "Company") may constitute "forward-looking statements" within the meaning of the United States Private Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because of the context of the statements including words such as the Company "believes","anticipates", "expects", "plans","estimates", or words of a similar nature.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: the general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; the foreign currency exchange rates; the economic conditions in the countries and regions in which the Company conducts business; the political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; the industry capacity; the ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition, availability and cost of seismic, drilling and other equipment; the ability of the Company to complete its capital programs; the ability of the Company to transport its products to market; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; the availability and cost of financing; the success of exploration and development activities; the timing and success of integrating the business and operations of acquired companies; the production levels; the uncertainty of reserve estimates; the actions by governmental authorities; the government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); the site restoration costs; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors, and management's course of action would depend upon its assessment of the future considering all information then available.

Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

Special note regarding non-GAAP financial measures

Management's discussion and analysis includes references to financial measures commonly used in the oil and gas industry, such as cash flow, cash flow per share and EBITDA. These financial measures are not defined by generally accepted accounting principles ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate the performance of the Company and its business segments. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance.

Management's discussion and analysis

Management's discussion and analysis of the financial condition and results of operations of the Company should be read in conjunction with the Company's audited consolidated financial statements and related notes for the year ended December 31, 2003. The consolidated financial statements have been prepared in accordance with Canadian GAAP. A reconciliation of Canadian GAAP to United States GAAP is included in note 16 to the consolidated financial statements. All dollar amounts are referenced in Canadian dollars, except where noted otherwise. The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of oil to estimate relative energy content. Production volumes are the Company's interest before royalties, and realized prices include the effect of derivative financial instruments gains and losses, except where noted otherwise. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

The following discussion details the Company's 2003 financial results compared to 2002 and 2001, including its capital program, and its outlook for 2004.

Objective and strategy

The Company's objective is to increase cash flow, net earnings, crude oil and natural gas production, reserves and net asset value on a per common share basis through the development of its existing crude oil and natural gas properties and by the discovery and acquisition of new reserves. The Company accomplishes this by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a measured approach to growth and investments and focuses on creating long-term shareholder wealth. The Company effectively allocates its capital by maintaining:

- Balance between its products, namely natural gas, light oil, Pelican Lake oil (1), primary heavy oil and thermal heavy oil;
- Balance between near-, mid- and long-term projects;
- Balance between acquisitions, exploitation and exploration; and
- Balance between sources of debt and a strong balance sheet.

(1) Pelican Lake oil is 14-17° API oil, but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.

Strategic acquisitions, such as Rio Alto Exploration Ltd. ("Rio Alto") in 2002, are a key component of the Company's strategy.

The Company's crude oil marketing strategy includes displacing medium sour crude oil from PADD II, supporting and participating in pipeline additions, and encouraging the development of projects that add conversion capacity.

Cost control is central to the Company's strategy. By controlling costs consistently throughout all industry cycles, the Company is able to achieve continued growth. Cost control is attained by area knowledge, by core area domination and by operating at a high working interest.

The year ended December 31, 2003, was another successful year in the execution of the Company's strategy. Highlights are as follows:

- Achieved record levels of cash flow and net earnings;
- Reduced long-term debt by $1,269 million through repayments of $740 million and foreign exchange gains of $529 million from the strengthening Canadian dollar;
- Achieved the Company's annual production guidance for both natural gas and crude oil and NGLs;
- Continued consolidation of the Company's North Sea interests. The Company now operates 99% of its production and owns an average working interest of approximately 80% in its North Sea properties. This provides the Company with the level of operatorship and working interests in the North Sea necessary to effectively control costs;
- Awarded major contracts for the Baobab Project, Offshore West Africa;
- Completed the Design Basis Memorandum ("DBM") phase of engineering for the Horizon Oil Sands Project ("Horizon Project") and commenced the third and final phase of pre-construction engineering, Engineering Design Specifications ("EDS");
- Completed the Joint Panel review for regulatory approvals of the Horizon Project; and
- Purchased 2,734,800 common shares for a total cost of $144 million under the Company's Normal Course Issuer Bid.

Acquisition of Rio Alto

In 2002, the Company paid cash of $850 million and issued 10,008,218 common shares to acquire all of the issued and outstanding common shares of Rio Alto by way of a plan of arrangement. This was a strategic acquisition as it increased the Company's natural gas production and added a new natural gas core region in Northwest Alberta. The Rio Alto acquisition is included in the results of operations commencing July 1, 2002.

Cash flow and net earnings

Financial highlights ($ millions, except per common share amounts)		**2003**		2002		2001
Revenue (1)	**$**	**5,972**	$	4,342	$	3,757
Cash flow from operations attributable to common shareholders (2)	**$**	**3,160**	$	2,254	$	1,920
Per common share – basic	**$**	**23.54**	$	17.63	$	15.83
– diluted	**$**	**23.06**	$	16.99	$	15.23
Net earnings attributable to common shareholders (3)	**$**	**1,407**	$	570	$	642
Per common share – basic	**$**	**10.48**	$	4.46	$	5.30
– diluted	**$**	**10.14**	$	4.31	$	5.17
Business combinations	**$**	**–**	$	2,393	$	–
Capital expenditures, net of dispositions	**$**	**2,506**	$	1,676	$	1,885

(1) Restated to conform to current year presentation.

(2) Cash flow from operations attributable to common shareholders is a non-GAAP term that represents net earnings attributable to common shareholders adjusted for non-cash items. The Company evaluates its performance and that of its business segments based on net earnings and cash flow from operations. The Company considers cash flow a key measure as it demonstrates the Company's ability and the ability of its business segments to generate the cash flow necessary to fund future growth through capital investment and to repay debt.

($ millions)		**2003**		2002		2001
Net earnings attributable to common shareholders	**$**	**1,407**	$	570	$	642
Non-cash items:						
Future tax on dividend on preferred securities		**(4)**		(4)		(4)
Revaluation of preferred securities, net of tax		**(18)**		(1)		8
Stock-based compensation expense		**200**		–		–
Depletion, depreciation and amortization		**1,565**		1,314		903
Unrealized foreign exchange (gain) loss		**(320)**		(35)		64
Loss on sale of United States assets		**–**		–		24
Deferred petroleum revenue tax		**(9)**		10		–
Future income tax expense		**339**		400		283
Cash flow from operations attributable to common shareholders	**$**	**3,160**	$	2,254	$	1,920

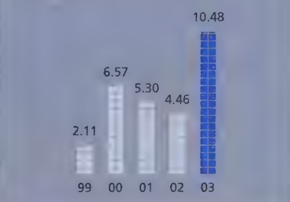
(3) After dividend and revaluation of preferred securities.

Cash flow from operations attributable to common shareholders reached record levels in 2003. Cash flow from operations attributable to common shareholders increased 40% to $3,160 million ($23.54 per common share), up from $2,254 million ($17.63 per common share) in 2002 and $1,920 million ($15.83 per common share) in 2001. The increase in cash flow resulted primarily from higher product prices and increased production volumes. In 2003, the Company's average price per barrel of crude oil and NGLs increased 6% to $31.59 from $29.76 in 2002 (2001 – $24.31). The Company's average natural gas price increased 60% to $6.02 per mcf from $3.76 per mcf in 2002 (2001 – $5.16 per mcf). Production volumes increased 9% to 458,814 boe/d from 420,722 boe/d in 2002 (2001– 359,347 boe/d). The increase in production volumes was primarily associated with an active capital expenditure program, the consolidation of working interests in the North Sea, and the impact of a full year of results relating to the acquisition of Rio Alto on July 1, 2002.

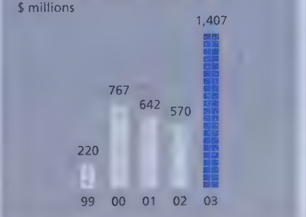
Net earnings attributable to common shareholders also reached record levels in 2003. Net earnings attributable to common shareholders increased 147% in 2003 to $1,407 million ($10.48 per common share), up from $570 million ($4.46 per common share) in 2002 and $642 million ($5.30 per common share) in 2001. Net earnings attributable to common shareholders in 2003 was impacted by the reduction in the Canadian federal and Alberta provincial corporate income tax rates, the strengthening Canadian dollar, which resulted in increased unrealized foreign exchange gains on the Company's US dollar denominated debt, and the recognition of stock-based compensation expense associated with the Company's Stock Option Plan.

Cash flow from operations attributable to common shareholders
$ millions

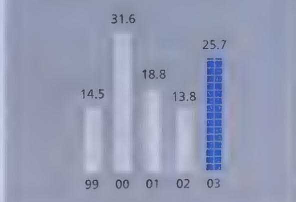
Net earnings attributable to common shareholders per share
$ per share



Net earnings attributable to common shareholders
$ millions



Return on average common shareholders' equity
percent



Operating highlights	**2003**	2002	2001
Crude oil and NGLs ($/bbl, except daily production)			
Daily production, before royalties (bbl/d)	**242,392**	215,335	206,323
Sales price (1)	**$ 31.59**	$ 29.76	$ 24.31
Royalties	**2.77**	3.16	2.17
Production expense	**10.28**	8.45	7.64
Netback	**$ 18.54**	$ 18.15	$ 14.50
Natural gas ($/mcf, except daily production)			
Daily production, before royalties (mmcf/d)	**1,299**	1,232	918
Sales price (1)	**$ 6.02**	$ 3.76	$ 5.16
Royalties	**1.32**	0.78	1.25
Production expense	**0.60**	0.57	0.51
Netback	**$ 4.10**	$ 2.41	$ 3.40
Barrel of oil equivalent ($/boe, except daily production)			
Daily production, before royalties (boe/d)	**458,814**	420,722	359,347
Sales price (1)	**$ 33.75**	$ 26.25	$ 27.15
Royalties	**5.20**	3.91	4.42
Production expense	**7.15**	5.99	5.69
Netback	**$ 21.40**	$ 16.35	$ 17.04

(1) Including financial instruments and transportation costs.

Business environment

	2003	2002	2001
WTI benchmark price (US$/bbl)	**$ 31.02**	$ 26.11	$ 25.91
Differential to LLB blend (US$/bbl)	**$ 8.55**	$ 6.50	$ 10.73
Condensate benchmark price (US$/bbl)	**$ 31.42**	$ 26.00	$ 28.12
NYMEX benchmark price (US$/mmbtu)	**$ 5.44**	$ 3.25	$ 4.38
AECO benchmark price (C$/GJ)	**$ 6.35**	$ 3.86	$ 5.92
US/Canadian dollar average exchange rate (US$)	**0.71**	0.64	0.65

World crude oil prices remained strong throughout 2003 due to concerns over supply relating to the war in Iraq, the strike in Venezuela, the unrest in Nigeria and rising worldwide demand. West Texas Intermediate ("WTI") prices increased 19% to average US$31.02 per bbl, up from US$26.11 per bbl in 2002 (2001 – US$25.91 per bbl). In 2003, the heavy oil differential averaged US$8.55 per bbl, up from US$6.50 per bbl in 2002 (2001 – US$10.73 per bbl). Natural gas prices increased in 2003 due to market forces of supply and demand. AECO natural gas price increased 65% to average $6.35 per GJ in 2003 compared to $3.86 per GJ in 2002 (2001 – $5.92 per GJ). NYMEX natural gas spot price increased 67% to average US$5.44 per mmbtu compared to US$3.25 per mmbtu in 2002 (2001 – US$4.38 per mmbtu).

Revenue

Product prices (1)	**2003**	2002	2001
Crude oil and NGLs ($/bbl)			
North America	**$ 27.77**	$ 27.04	$ 21.00
North Sea	**$ 42.43**	$ 39.79	$ 38.66
Offshore West Africa	**$ 36.47**	$ 40.10	$ 33.57
Company average	**$ 31.59**	$ 29.76	$ 24.31
Natural gas ($/mcf)			
North America	**$ 6.14**	$ 3.78	$ 5.19
North Sea	**$ 3.03**	$ 2.75	$ 2.51
Offshore West Africa	**$ 4.37**	$ 4.82	$ –
Company average	**$ 6.02**	$ 3.76	$ 5.16
Percentage of revenue (excluding midstream revenue)			
Crude oil and NGLs	**49%**	58%	52%
Natural gas	**51%**	42%	48%

(1) Including financial instruments and transportation costs.

Analysis of changes in revenue

($ millions)	2001	Changes due to Volumes	Changes due to Prices	Changes due to Other	2002	**Changes due to Volumes**	**Changes due to Prices**	**Changes due to Other**	**2003**
North America									
Crude oil and NGLs	$ 1,339	$ 23	$ 386	$ –	$ 1,748	**$ 52**	**$ 49**	**$ –**	**$ 1,849**
Natural gas	1,824	565	(527)	–	1,862	**56**	**1,062**	**–**	**2,980**
	3,163	588	(141)	–	3,610	**108**	**1,111**	**–**	**4,829**
North Sea									
Crude oil and NGLs	523	37	24	–	584	**261**	**36**	**–**	**881**
Natural gas	11	14	3	–	28	**19**	**33**	**–**	**80**
	534	51	27	–	612	**280**	**69**	**–**	**961**
Offshore West Africa									
Crude oil and NGLs	42	42	16	–	100	**56**	**(14)**	**–**	**142**
Natural gas	–	2	–	–	2	**13**	**(1)**	**–**	**14**
	42	44	16	–	102	**69**	**(15)**	**–**	**156**
Subtotal									
Crude oil and NGLs	1,904	102	426	–	2,432	**369**	**71**	**–**	**2,872**
Natural gas	1,835	581	(524)	–	1,892	**88**	**1,094**	**–**	**3,074**
	3,739	683	(98)	–	4,324	**457**	**1,165**	**–**	**5,946**
Midstream	27	–	–	25	52	**–**	**–**	**9**	**61**
Intersegment eliminations (1)	(9)	–	–	(25)	(34)	**–**	**–**	**(1)**	**(35)**
Total	$ 3,757	$ 683	$ (98)	$ –	$ 4,342	**$ 457**	**$ 1,165**	**$ 8**	**$ 5,972**

(1) Eliminates internal transportation and electricity charges.

Revenue rose 38% to $5,972 million in 2003, up from $4,342 million in 2002 (2001 – $3,757 million). In 2003, 19% of the Company's crude oil and natural gas revenue was generated outside of North America, up from 16% in 2002 (2001 – 15%). North Sea accounted for 16% of revenue in 2003 and 14% in 2002 (2001 – 14%), and Offshore West Africa accounted for 3% of revenue in 2003 and 2% in 2002 (2001 – 1%).

Crude oil and NGLs pricing realized by the Company is directly correlated with fluctuations in world oil pricing and heavy oil differentials. The realized crude oil and NGLs price earned by the Company in 2003 increased 6% to average $31.59 per bbl for the year, up from $29.76 per bbl in 2002 (2001 – $24.31 per bbl). The Company's realized crude oil price was impacted by the increase in world oil prices, the higher heavy oil differential, and the strengthening Canadian dollar (see Sensitivity Analysis).

Natural gas prices increased 60% to average $6.02 per mcf, up from $3.76 per mcf in 2002 (2001 – $5.16 per mcf), due to market forces of supply and demand in 2003. Lower demand and higher storage levels in the first half of the year impacted natural gas prices in 2002.

The Company uses certain financial instruments to protect against downside commodity prices received on the sale of certain crude oil and natural gas production to ensure adequate resources are available for its capital program. The price realized from the sale of crude oil was reduced by $1.07 per bbl in 2003 compared to $1.46 per bbl in 2002 (2001 – increase of $0.86 per bbl) due to the impact of financial instruments. In addition, the price realized from the sale of natural gas was reduced by $0.19 per mcf in 2003 compared to a reduction of $0.01 per mcf in 2002 (2001 – reduction of $0.29 per mcf) due to the impact of financial instruments. The financial instruments as at December 31, 2003, are summarized in note 10 to the consolidated financial statements.

A comparison of the price received for the Company's North America production is as follows:

	2003	2002	2001
Wellhead Price (1)			
Light crude oil and NGLs (C$/bbl)	**$ 35.92**	$ 32.88	$ 34.73
Pelican Lake crude oil (C$/bbl)	**$ 26.31**	$ 25.92	$ 19.46
Primary heavy crude oil (C$/bbl)	**$ 24.70**	$ 25.40	$ 17.64
Thermal heavy crude oil (C$/bbl)	**$ 23.85**	$ 24.12	$ 15.20
Natural gas (C$/mcf)	**$ 6.14**	$ 3.78	$ 5.19

(1) Including financial instruments and transportation costs.

Daily production, before royalties

	2003	2002	2001
Crude oil and NGLs (bbl/d)			
North America	**174,895**	169,675	166,675
North Sea	**56,869**	38,876	36,252
Offshore West Africa	**10,628**	6,784	3,396
Total	**242,392**	215,335	206,323
Natural gas (mmcf/d)			
North America	**1,245**	1,204	906
North Sea	**46**	27	12
Offshore West Africa	**8**	1	–
Total	**1,299**	1,232	918
Product mix			
Light crude oil and NGLs	**25%**	21%	21%
Pelican Lake crude oil	**5%**	7%	9%
Primary heavy crude oil	**15%**	14%	16%
Thermal heavy crude oil	**8%**	9%	11%
Natural gas	**47%**	49%	43%

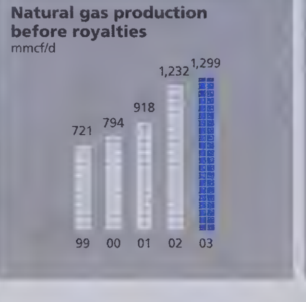
The Company's daily crude oil and NGLs production increased 13% or 27,057 bbl/d to average 242,392 bbl/d in 2003, up from 215,335 bbl/d in 2002 (2001 – 206,323 bbl/d). Crude oil and NGLs production in 2003 increased in all segments from the previous year and was in line with production guidance provided.

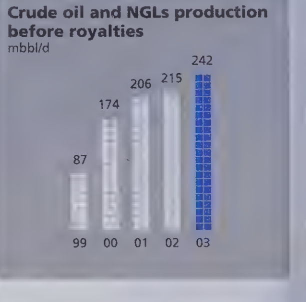
Crude oil and NGLs production in North America for the year ended December 31, 2003 increased 3% or 5,220 bbl/d to average 174,895 bbl/d, up from 169,675 bbl/d in 2002 (2001 – 166,675 bbl/d). The increase in North America production is attributable to heavy oil drilling and recompletion activity in 2003, property acquisitions in its core operating regions in 2002, and the impact of a full year production from the properties acquired in the Rio Alto acquisition. Crude oil production from the Pelican Lake Field declined as a result of the implementation of the water flood program, which required producing wells to be converted to injectors.

Crude oil production from the North Sea for the year ended December 31, 2003 increased 46% or 17,993 bbl/d to average 56,869 bbl/d, up from 38,876 bbl/d in 2002 (2001 – 36,252 bbl/d). The increase was a result of drilling activities, which focused on unswept oil reserves within the Ninian, Murchison and Columba Fields, recompletion activities where a number of wells were re-entered to access behind pipe reserves, and the continued consolidation of the Company's working interests in the North Sea. Crude oil production from the North Sea in 2003 was also impacted by two unscheduled turnarounds on the Ninian South Platform. Production from the Ninian South Platform was shut in from late March 2003 to late April 2003 in order to replace critical pipework to significantly increase the reliability and integrity of the Platform.

Offshore West Africa crude oil production for the year ended December 31, 2003, increased 57% or 3,844 bbl/d to average 10,628 bbl/d, up from 6,784 bbl/d in 2002 (2001 – 3,396 bbl/d). The increase in crude oil production is due to the commencement of production from the Company's operated Espoir Field, located offshore Côte d'Ivoire, in 2002. In addition, crude oil production increased due to the perforation of the upper zone of the East Espoir structure in the second quarter of 2003, and the completion of the fourth water injection well and two additional producing wells in 2003.

The Company continues to look for opportunities to expand its heavy oil markets. In particular, the Company is testing a 50/50 blend of bitumen and synthetic crude oil called "Synbit". Synbit has similar properties to medium sour crude oil and is expected to decrease the demand for supplies of condensate currently blended with bitumen. The Company is currently marketing 34,000 bbl/d of Synbit to refiners located in the US Midwest and plans to expand this effort throughout 2004 to build a solid new market for both heavy and synthetic crude oil.





Natural gas continues to represent the Company's largest product offering, accounting for 47% of the Company's total production in 2003 compared to 49% of total production in 2002 (2001 – 43%). Natural gas production increased 5% or 67 mmcf/d to average 1,299 mmcf/d, up from 1,232 mmcf/d in 2002 (2001 – 918 mmcf/d). Annual natural gas production was in line with the production guidance provided.

North America accounts for 96% of the Company's natural gas production in 2003, down from 98% in 2002 (2001 – 99%). Overall, natural gas production in North America increased 3% or 41 mmcf/d to average 1,245 mmcf/d, up from 1,204 mmcf/d in 2002 (2001 – 906 mmcf/d). The increase in natural gas production was due to ongoing drilling activities and the acquisition of Rio Alto on July 1, 2002. Natural gas production in 2003 was impacted by steep production declines from the Ladyfern Field. Ladyfern natural gas production decreased 67% or 112 mmcf/d to average 56 mmcf/d, down from 168 mmcf/d in 2002 (2001 – 40 mmcf/d). Production of natural gas was also impacted by the shut in of approximately 11 mmcf/d of the Company's natural gas production in the Athabasca Wabiskaw-McMurray oilsands area pursuant to the decision of the Alberta Energy and Utilities Board ("EUB") effective September 1, 2003.

North Sea natural gas production increased 70% or 19 mmcf/d to average 46 mmcf/d, up from 27 mmcf/d in 2002 (2001 – 12 mmcf/d). The increase was due to the acquisition of additional interests in the Banff Field. Natural gas production from the North Sea in 2004 is expected to decrease due to the implementation of the natural gas re-injection program on the Banff Field to maximize recovery from the reservoir.

Natural gas production in Offshore West Africa increased 7 mmcf/d to average 8 mmcf/d, up from 1 mmcf/d in 2002 (2001 – nil). Production increased due to the completion of the natural gas pipeline in the Espoir Field in the third quarter of 2002. Natural gas production also increased from the previous year due to the perforation of the upper zone of the East Espoir structure in the second quarter of 2003 and the drilling of additional production and injection wells in 2003.

Royalties

		2003		2002		2001
Crude oil and NGLs ($/bbl)						
North America	**$**	**3.79**	$	3.42	$	2.22
North Sea	**$**	**(0.03)**	$	2.30	$	2.10
Offshore West Africa	**$**	**1.08**	$	1.35	$	0.93
Company average	**$**	**2.77**	$	3.16	$	2.17
Natural gas ($/mcf)						
North America	**$**	**1.38**	$	0.80	$	1.26
Offshore West Africa	**$**	**0.13**	$	0.15	$	–
Company average	**$**	**1.32**	$	0.78	$	1.25
Company average ($/boe)	**$**	**5.20**	$	3.91	$	4.42
Percentage of revenue (1)(2)						
Crude oil and NGLs		**9%**		10%		9%
Natural gas		**21%**		21%		23%

(1) Excludes the impact of financial instruments.
(2) Transportation costs netted against revenue.

Crude oil and NGLs royalties in North America increased to $3.79 per bbl, up from $3.42 per bbl in 2002 (2001 – $2.22 per bbl), due to certain primary and thermal heavy oil projects reaching payout and becoming subject to higher government royalty rates. The majority of the Company's oil sands projects continue to benefit from reduced royalty rates as a result of the Alberta program to promote development of oil sands resources, which provides a reduced royalty rate until an oil sands project recovers its capital costs.

Effective January 1, 2003, government royalties in the North Sea were eliminated. In 2003, the Company received a refund of royalties related to the Ninian Field. As a result North Sea crude oil royalties recovered $0.03 per bbl as opposed to an expense of $2.30 per bbl in 2002 (2001 – $2.10 per bbl).

Offshore West Africa crude oil royalties decreased to $1.08 per bbl, down from $1.35 per bbl in 2002 (2001 – $0.93 per bbl) due to fluctuations in realized crude oil prices.

Natural gas royalties for the Company increased to $1.32 per mcf, up from $0.78 per mcf in 2002 (2001 – $1.25 per mcf), due to the overall increase in natural gas prices. North America natural gas royalties have a strong correlation to changes in natural gas prices.

Production expense

	2003	2002	2001
Crude oil and NGLs ($/bbl)			
North America	**$ 9.14**	$ 6.73	$ 7.05
North Sea	**$ 14.07**	$ 15.06	$ 9.00
Offshore West Africa	**$ 8.68**	$ 13.63	$ 21.77
Company average	**$ 10.28**	$ 8.45	$ 7.64
Natural gas ($/mcf)			
North America	**$ 0.57**	$ 0.55	$ 0.50
North Sea	**$ 1.33**	$ 1.53	$ 0.94
Offshore West Africa	**$ 1.39**	$ 1.81	$ –
Company average	**$ 0.60**	$ 0.57	$ 0.51
Company average ($/boe)	**$ 7.15**	$ 5.99	$ 5.69

Production expense increased to $7.15 per boe, up from $5.99 per boe in 2002 (2001 – $5.69 per boe). The increase was primarily related to higher costs associated with operations in North America. North America crude oil and NGLs production expense increased to $9.14 per bbl from $6.73 per bbl in 2002 (2001 – $7.05 per bbl). The increase was mainly a result of higher repair and maintenance costs incurred with regard to property acquisitions as well as costs associated with the conversion and implementation of the Pelican Lake water flood pilots. The increase was also impacted by the cost of fuel gas used in the generation of steam in the Company's thermal oil operations.

North Sea crude oil production expense decreased in 2003 to $14.07 per bbl from $15.06 per bbl in 2002 (2001 – $9.00 per bbl), due to the timing of maintenance work and changes in production volumes on a relatively fixed cost base. Production expense in the North Sea was higher than normal in 2002 due to costs associated with rectifying a natural gas pipeline blockage in the Kyle Field.

Offshore West Africa crude oil production expense decreased to $8.68 per bbl from $13.63 per bbl in 2002 (2001 – $21.77 per bbl) resulting from production increases in the Espoir Field. The Espoir Field commenced operations in the first quarter of 2002. Production expenses are largely fixed in nature and therefore decreased on a per barrel basis as production increased. The higher production expense in 2001 was related to costs associated with the Kiame Field, located offshore Angola, which ceased operations early in 2002.

Natural gas production expense for the year 2003 increased to $0.60 per mcf, up from $0.57 per mcf in 2002 (2001 – $0.51 per mcf). North America natural gas production expense increased to $0.57 per mcf, up from $0.55 per mcf in 2002 (2001 – $0.50 per mcf), as a result of a general increase in service costs associated with increased industry activity.

Midstream

($ millions)	2003	2002	2001
Revenue	**$ 61**	$ 52	$ 27
Operating costs	**15**	14	11
Operating cash flow	**46**	38	16
Depreciation	**7**	8	4
Segment earnings before taxes	**$ 39**	$ 30	$ 12

The Company's midstream assets consist of three crude oil pipeline systems and an 84-megawatt cogeneration plant at Primrose where the Company has a 50% working interest. Approximately 85% of the Company's heavy oil production was transported to international liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline, which commenced operations in late 2001. The midstream pipeline assets allow the Company to transport its own production volumes at reduced costs compared to other transportation alternatives as well as earn third party revenue. This transportation control enhances the Company's ability to control the full range of costs associated with the development and marketing of its heavy oil.

Revenue from the midstream assets increased 17% to $61 million, up from $52 million in 2002 (2001 – $27 million). The increase in revenue, operating cashflow and segment earnings before taxes was due to higher electricity prices received in the first quarter of 2003 and increased revenue generated as a result of the expansion of the ECHO Pipeline. The expansion of the ECHO Pipeline was completed in October 2003 and increased capacity to 72 mbbl/d from 58 mbbl/d.

The Cold Lake Pipeline Limited Partnership, in which the Company has a 15% working interest, will be investing $16 million in 2004 to construct new facilities to allow shipment of up to 60,000 bbl/d of Synbit product. The new Synbit product will include light synthetic oil as a blending component to dilute the heavy, tar-like Cold Lake bitumen. The Synbit project will involve construction of two 80,000 barrel storage tanks, pumping facilities and metering equipment on the Cold Lake system. Regulatory approvals have been obtained and construction activity is currently underway.

Depletion, depreciation and amortization (1)

($ millions, except per boe amounts)		2003		2002		2001
North America	$	1,248	$	1,033	$	746
North Sea		268		193		129
Offshore West Africa		42		80		24
Expense	$	1,558	$	1,306	$	899
$/boe	$	9.30	$	8.51	$	6.86

(1) DD&A excludes depreciation on midstream assets.

Depletion, depreciation and amortization ("DD&A") increased in total and per boe to $1,558 million or $9.30 per boe from $1,306 million or $8.51 per boe in 2002 (2001 – $899 million or $6.86 per boe). These increases were due to the higher finding and development costs associated with natural gas exploration in North America, the allocation of the acquisition costs associated with Rio Alto, and future abandonment costs associated with the acquisition of additional interests in the North Sea. In addition, DD&A included the write-off of $12 million of costs associated with the Company's exploration activity in offshore France in 2003. In 2002, DD&A included the write-off of $51 million as a result of the Company's decision to exit from its interests in Block 19, Angola, and from the Aje Field, Nigeria.

Administration expense

($ millions, except per boe amounts)		2003		2002		2001
Gross cost	$	262	$	147	$	110
$/boe	$	1.57	$	0.96	$	0.84
Net expense	$	87	$	61	$	38
$/boe	$	0.52	$	0.40	$	0.29

Gross administration expense increased to $1.57 per boe from $0.96 per boe in 2002 (2001 – $0.84 per boe) mainly due to higher staffing levels associated with the Company's expanding asset base and costs associated with the Horizon Project. Gross administration expense also increased as a result of higher costs related to the assumption of operatorship of certain fields in the North Sea. Net administration expense, after operator recoveries and capitalized overhead relating to exploration and development in the North Sea and Offshore West Africa as well as the Horizon Project, increased to $0.52 per boe in 2003 from $0.40 per boe in 2002 (2001 – $0.29 per boe).

Stock-based compensation

($ millions, except per boe amounts)		2003		2002		2001
Stock-based compensation expense	$	200	$	–	$	–
$/boe	$	1.20	$	–	$	–

In June 2003, the Board of Directors approved an amendment to the Company's Stock Option Plan (the "Option Plan") that provides current employees, officers and directors (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. Amendments to the Option Plan balance the need for a long-term compensation program to retain employees with reducing the impact of dilution on current shareholders and the reporting of the expense associated with stock options. Transparency of the cost of the Option Plan is increased since changes in the intrinsic value of outstanding stock options are expensed. The cash payment feature provides option holders with substantially the same benefits and allows them to realize the value of their options through a simplified administration process.

As a result of the amendment to the Option Plan, the Company has recorded a liability at December 31, 2003, of $171 million for expected cash settlements based on the intrinsic value of the outstanding stock options (the difference between the exercise price of the stock options and the market price of the Company's common shares). Compensation expense for 2003 is $200 million ($136 million net of tax). The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the net change is recognized in net earnings. In 2003, the Company paid $31 million in cash settlements for stock options surrendered.

Interest expense

($ millions, except per boe amounts)		2003		2002		2001
Interest expense	$	157	$	159	$	138
$/boe	$	0.94	$	1.03	$	1.05
Average effective interest rate		4.7%		4.5%		5.4%

Interest expense decreased to $157 million in 2003 from $159 million in 2002 (2001 – $138 million) due to lower average outstanding debt levels as the Company used excess cash flow generated to repay $740 million of long-term debt in 2003. The impact of the lower debt levels was partially offset by the higher average effective interest rate of 4.7%, up from 4.5% in 2002 (2001 – 5.4%). In addition, the strengthening Canadian dollar reduced the Canadian equivalent interest expense on the Company's US dollar denominated debt. Interest expense decreased to $0.94 per boe in 2003 compared to $1.03 per boe in 2002 (2001 – $1.05 per boe) as a result of the lower average outstanding debt levels and higher production. The Company continues to benefit from the lower short-term interest rates as its fixed-rate debt accounts for only 38% of total debt outstanding after interest rates swaps (see note 10 to the consolidated financial statements) as at December 31, 2003 (2002 – 40%, 2001 – 21%).

Foreign exchange

($ millions)	**2003**	2002	2001
Realized foreign exchange loss (gain)	**$ 8**	$ 4	$ (1)
Unrealized foreign exchange (gain) loss	**(320)**	(35)	64
Total	**$ (312)**	$ (31)	$ 63

The Canadian dollar increased to US$0.77 at December 31, 2003, compared to US$0.63 at January 1, 2003, resulting in an unrealized foreign exchange gain on the Company's US dollar denominated debt. The Canadian dollar averaged US$0.71 in 2003, up from US$0.64 in 2002 (2001 – US$0.65).

The majority of the Company's borrowings are denominated in US dollars. At December 31, 2003, the Company's US dollar denominated debt amounted to US$1,965 million compared to US$1,968 million in 2002 (2001 – US$899 million). US dollar denominated debt represented 91% of total debt outstanding at December 31, 2003 (2002 – 76%, 2001 – 53%). Due to the higher proportion of US dollar denominated debt outstanding, the Company's net earnings are more sensitive to fluctuations in the Canadian dollar.

In order to mitigate a portion of the volatility associated with the Canadian dollar, the Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment in shareholders' equity in the consolidated balance sheets.

The Company's realized product prices are sensitive to currency exchange rates. Recent increases in the value of the Canadian dollar in relation to the US dollar had a negative impact on the Company's commodity price realized (see Sensitivity Analysis).

Taxes

($ millions, except income tax rates)	**2003**	2002	2001
Taxes other than income tax			
Current	**$ 116**	$ 53	$ 69
Deferred	**(9)**	10	–
Total	**$ 107**	$ 63	$ 69
Current income tax			
North America – Current income tax	**$ 43**	$ –	$ –
North America – Large Corporations Tax	**16**	21	15
North Sea	**23**	(19)	62
Offshore West Africa	**10**	6	–
Total	**$ 92**	$ 8	$ 77
Future income tax	**$ 339**	$ 400	$ 283
Effective income tax rate	**23.6%**	41.6%	35.4%

Taxes other than income tax consist of current and deferred petroleum revenue tax ("PRT"), other international taxes and provincial capital taxes and surcharges. PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income after certain deductions including abandonment expenditures. Taxes other than income tax increased to $107 million or $0.64 per boe in 2003, up from $63 million or $0.41 per boe in 2002 (2001 – $69 million or $0.53 per boe). The increase in taxes other than income tax was mainly due to the higher netback earned in the North Sea as a result of higher crude oil prices and higher production levels. North Sea PRT accounts for $97 million or $0.58 per boe in 2003 compared to $51 million or $0.33 per boe in 2002 (2001 – $59 million or $0.45 per boe).

Current income tax in the North Sea increased to $23 million or $0.14 per boe, up from a recovery of $19 million or $0.13 per boe in 2002 (2001 – expense of $62 million or $0.47 per boe). The increase in the current income tax expense was a result of increased production and higher crude oil prices. The North Sea current income tax was also impacted by changes in the tax rules in the North Sea. In 2002, a supplementary charge of 10% on

profits from UK North Sea crude oil and natural gas production was introduced. The North Sea supplementary charge, which took effect April 17, 2002, is in addition to the corporate income tax rate of 30% and excludes any deduction for financing costs. In addition, the first year capital allowance rate for plant and machinery expenditures was increased to 100% from the previous rate of 25%.

Taxable income from the conventional crude oil and natural gas business in Canada is generated by partnerships and the related income taxes will be payable in the following year. Current income taxes have been provided on the basis of the corporate structure and available income tax deductions. No current income tax provision was required for North America in 2002 and 2001.

The Company is liable for the payment of Federal LCT. LCT decreased to $16 million or $0.09 per boe from $21 million or $0.14 per boe (2001 – $15 million or $0.11 per boe) as a result of the Company being taxable and paying the Federal corporate surtax.

In 2003, the Canadian Federal Government passed legislation to eliminate the federal Large Corporations Tax ("LCT") over a five-year period starting January 1, 2004. The LCT was levied at a rate of 0.225% of the Company's taxable capital employed in Canada in 2003 (2004 – 0.2%). The Federal Government also passed legislation to reduce the corporate income tax rate on income from resource activities from 28% to 21% over a five-year period starting January 1, 2003, bringing the resource industry in line with the general corporate income tax rate. As part of the corporate income tax rate reduction, the legislation also provides for the elimination of the existing 25% resource allowance and the introduction of a deduction for actual provincial and other crown royalties paid. As a result of these changes, the future income tax liability in North America was decreased by $247 million in 2003. In 2003 the North America future income tax liability was also reduced by $31 million as a result of a reduction in the Alberta corporate income tax rate (2002 – $21 million, 2001 – $63 million).

The Company's future income tax provision for 2003 decreased to $339 million ($2.02 per boe), down from $400 million ($2.61 per boe) in 2002 (2001 – $283 million or $2.02 per boe) due to changes noted above. In 2002, the future income tax liability in the North Sea was increased by $34 million as a result of the introduction in the UK of a 10% supplementary charge on profits from North Sea crude oil and natural gas production. The increase in the North Sea future income tax liability was partially offset by a $21 million decrease in the North America future income tax liability as a result of a reduction in the Alberta provincial corporate income tax rate in the second quarter of 2002. Future income taxes also increased in 2002 because of the increased capital allowance rates in the North Sea, resulting in a lower current tax expense and a higher future income tax expense.

The Company's effective tax rate decreased to 23.6% for 2003 from 41.6% for 2002 (2001 – 35.4%) as a result of the reductions in the Federal and Alberta corporate income tax rates in 2003.

It is anticipated that, based on the current availability of approximately $4 billion of tax pools in Canada at the end of 2003 and current commodity strip prices, the Company will be cash taxable in Canada in 2004 in the amount of $100 million to $175 million.

Liquidity and capital resources

($ millions, except ratios)	2003	2002	2001
Working capital deficit (1)	**$ 505**	$ 14	$ 6
Long-term debt	**2,645**	4,074	2,669
Net debt	**$ 3,150**	$ 4,088	$ 2,675
Shareholders' equity			
Preferred securities	**$ 103**	$ 126	$ 127
Share capital	**2,353**	2,304	1,698
Retained earnings	**3,644**	2,414	1,908
Foreign currency translation adjustment	**17**	24	73
Total	**$ 6,117**	$ 4,868	$ 3,806
Debt to cash flow (1)	**0.9x**	1.8x	1.4x
Debt to EBITDA (1)(2)(3)	**0.8x**	1.6x	1.3x
Debt to book capitalization (1)	**31.6%**	45.6%	41.2%
Debt to market capitalization (1)	**24.2%**	38.9%	34.9%
After tax return on average common shareholders' equity (2)	**25.7%**	13.8%	18.8%
After tax return on average capital employed (2)	**16.7%**	8.9%	12.0%

(1) Includes current portion of long-term debt.
(2) Based on trailing 12-month activity.
(3) Earnings before interest, taxes, depletion, depreciation and amortization.

The Company recognizes the need for a strong financial position in order to withstand volatile crude oil and natural gas commodity prices and the operational risks inherent in the crude oil and natural gas business environment.

Long-term debt

Long-term debt including current portion at December 31, 2003, decreased $1,269 million from the prior year. The decrease resulted in a debt to EBITDA ratio of 0.8x and a debt to book capitalization of 31.6% compared to a debt to EBITDA ratio of 1.6x and a debt to book capitalization of 45.6% in 2002. These ratios are currently below the Company's guidelines for balance sheet management of debt to EBITDA of 1.5x to 2.0x and debt to book capitalization of 40% to 45%.

At December 31, 2003, the Company had:

- Approximately $1.6 billion of available unused bank credit facilities;
- A fixed / floating interest rate mix of 38% / 62%;
- An average cost of borrowing of approximately 4.7%;
- 91% of borrowings denominated in US dollars; and
- 91% of total long-term debt as non-bank-based borrowing with an average maturity of 14.6 years.

In 2003, $740 million of long-term debt was repaid. Long-term debt was also reduced by an additional $529 million as a result of foreign exchange gains on US dollar denominated debt. Higher than budgeted prices received for the Company's products during 2003 resulted in increased cash flow over the budget established in late 2002. Early in 2003, the Company decided to allocate a minimum of 50% of its cash flow surplus toward debt repayment. The remaining excess was directed to the Company's authorized share buy-back program and additional expenditures on conventional crude oil and natural gas opportunities. The largest portion of the additional capital expenditures took place in the fourth quarter of 2003 and accordingly did not add materially to the Company's 2003 average production volumes.

In May 2003, the Company filed a short form prospectus that allows for the issue of up to US$2 billion of debt securities in the United States until June 2005. If issued, these securities will bear interest as determined at the date of issuance. In addition, the Company maintains a shelf prospectus in Canada for the offering of up to $1 billion of medium-term notes in Canada. If issued, these securities will bear interest as determined at the date of issuance. Future offerings under the shelf prospectuses will provide flexibility to the Company's debt investment base, extend maturities and provide balance in the fixed to floating interest rate mix.

In May 2003, the Company prepaid the US$50 million, 6.50% senior unsecured notes due May 1, 2008. The final principal repayment on the 6.95% senior unsecured notes was made September 30, 2003.

The ratings of the Company's debt securities and its relationships with principal banks are extremely important to the Company as it continues to expand and grow. Hence, the Company's management will continually undertake to maintain a strong balance sheet and financial position. The Company's debt securities are rated "Baa1" by Moody's Investor Services Inc., "BBB+" by Standard & Poors Corporation and "BBB(high)" by Dominion Bond Rating Services Limited. As at December 31, 2003, the Company had unsecured bank credit facilities of $1,925 million compared to $2,275 million at the close of 2002 (2001 – $1,840 million). During 2003, the Company repaid and cancelled a $500 million acquisition term credit facility.

With respect to the Horizon Project, financing of the first phase of development will be guided by the competing principles of retaining as much direct ownership interest as possible while maintaining current strong debt ratings and not issuing additional equity in common shares. The Company is also investigating the use of long-term commodity hedges in order to reduce cash flow risks during the construction phase. The Company could also look to offload capital commitments through the acceptance of complementary business partners, or potentially, project joint venture partners. Recent commodity price increases have significantly strengthened the balance sheet of the Company, thereby placing it in a better position to achieve all three of its guiding principles.

Share capital

The Company is authorized to issue an unlimited number of common shares. As at December 31, 2003 and 2002, there were 134 million common shares outstanding. In addition, the Company is also authorized to issue 200,000 Class 1 preferred shares. There were no preferred shares outstanding during these periods.

During 2003, the Company issued 2,690 thousand common shares from the exercise of stock options for proceeds of $89 million. In addition, 2,735 thousand common shares were purchased for cancellation under the Normal Course Issuer Bid for a total cost of $144 million, resulting in 45 thousand fewer outstanding common shares than at the beginning of the year.

In 2002, the Company issued 10 million common shares at an attributed value of $522 million as part of the consideration to acquire Rio Alto. A further 2,523 thousand common shares were issued from the exercise of stock options throughout 2002 for proceeds of $82 million. The Company issued 60,000 flow-through common shares to a Director of the Company at a price of $39.00 per common share, for total proceeds of $2 million net of tax. The value of the flow-through common shares was determined based on the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the allotment.

In January 2004, the Company renewed its Normal Course Issuer Bid allowing it to purchase up to 6,690,385 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2004, and ending January 23, 2005. As at February 19, 2004, the Company has not purchased any additional shares under the renewed Normal Course Issuer Bid.

The Company's Board of Directors has approved an increase in the annual dividend paid by the Company to $0.80 per common share in 2004, up from the previous level of $0.60 per common share. The 33% increase recognizes the stability of the Company's increased cash flow and provides a further return to shareholders. This is the fourth consecutive year in which the Company has paid dividends and the third consecutive year of an increase in the distribution paid to its shareholders. The increased dividend will become effective with the quarterly payment of $0.20 per common share to be paid on April 1, 2004.

The Company declared dividends on common shares in the amount of $81 million or $0.60 per common share during the year ended December 31, 2003, up from $64 million or $0.50 per common share in 2002 (2001 – $49 million, $0.40 per common share).

In order to increase the liquidity of its common shares, the Board of Directors will recommend to its shareholders to subdivide the Company's common shares on a two for one basis, which will result in an increase in the Company's total outstanding common shares to approximately 268 million common shares. This recommendation will be voted on by the shareholders at the Annual and Special Meeting of Shareholders to be held on May 6, 2004. As at February 19, 2004, the Company has 134,063,267 common shares outstanding.

Off balance sheet arrangements and financial instruments

The Company has operating leases in place on a variety of equipment. These operating leases require periodic lease payments, which are recorded as production expenses. The Company also utilizes various financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes.

The Company enters into commodity price contracts to hedge anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. Gains or losses on these contracts are included in crude oil and natural gas revenue at the time of sale of the related product. Foreign exchange translation gains and losses on foreign currency denominated financial instruments used to hedge future US dollar denominated crude oil and natural gas sales are recognized in revenue at the time of sale of the related product. The Company inherited a foreign currency swap agreement from Rio Alto that hedges a foreign currency denominated long-term debt instrument through an offsetting forward exchange contract. The foreign exchange translation gains and losses on the financial instrument are used to offset the respective translation gains and losses recognized on the long-term debt. The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap agreements require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Gains or losses on these financial instruments are included in interest expense when realized. The related amount receivable from or payable to counterparties is included as an adjustment to accrued interest in the consolidated balance sheets. Realized gains and losses on the termination of financial instruments that have been accounted for as hedges are deferred under non-current assets or liabilities on the consolidated balance sheets and recognized in net earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized gain or loss is recognized in net earnings. The fair value of these financial instruments is disclosed in note 10 to the consolidated financial statements.

Commitments

The Company has various commitments primarily related to debt, operating leases and demand charges on firm transportation agreements. The following table summarizes the Company's commitments as at December 31, 2003.

($ millions)	2004	2005	2006	2007	2008	Thereafter
Natural gas transportation	$ 180	$ 169	$ 143	$ 103	$ 77	$ 194
Crude oil transportation and pipeline	$ 15	$ 13	$ 13	$ 15	$ 13	$ 167
Offshore equipment operating lease	$ 169	$ 129	$ 75	$ 75	$ 75	$ 367
Electricity	$ 28	$ 27	$ 27	$ –	$ –	$ –
Office lease	$ 20	$ 20	$ 19	$ 17	$ 16	$ 50
Processing	$ 6	$ 5	$ 2	$ –	$ –	$ –
Preferred securities	$ –	$ –	$ –	$ –	$ –	$ 103
Long-term debt	$ 184	$ 194	$ –	$ 165	$ 40	$ 1,978

Capital expenditures

($ millions)	2003	2002	2001
Business combinations	**$ –**	$ 2,393	$ –
Expenditures on property, plant and equipment			
Net property acquisitions	**$ 336**	$ 440	$ 519
Land acquisition and retention	**154**	114	101
Seismic evaluations	**77**	63	95
Well drilling, completion and equipping	**1,194**	626	635
Pipeline and production facilities	**522**	292	395
Total net reserve replacement expenditures	**2,283**	1,535	1,745
Horizon Oil Sands Project	**152**	68	27
Midstream	**11**	20	97
Abandonments	**40**	43	10
Head office	**20**	10	6
Total net capital expenditures	**$ 2,506**	$ 1,676	$ 1,885
By segment (excluding business combinations)			
North America	**$ 1,815**	$ 1,065	$ 1,459
North Sea	**342**	333	98
Offshore West Africa	**186**	190	204
Horizon Project	**152**	68	27
Midstream	**11**	20	97
Total	**$ 2,506**	$ 1,676	$ 1,885

The Company's strategy is focused on continuing to build a diversified asset base that is balanced between products, namely natural gas, light oil, Pelican Lake oil, primary heavy oil and thermal heavy oil.

Capital expenditures were $2,506 million in 2003 compared to $1,676 million in 2002, excluding the acquisition of Rio Alto (2001 – $1,885 million). North America accounted for 79% of total capital expenditures, up from 69% in 2002 (2001 – 84%). In 2003, the Company's drilling activity increased 199% with the drilling of 1,353 net wells (excluding stratigraphic test/service wells), up from 453 net wells drilled in 2002 (2001 – 739 net wells). The Company drilled 777 net natural gas wells, up 380% from the 162 net wells in 2002 (2001 – 476 net wells) and 458 net crude oil wells, up 73% from the 264 net wells in 2002 (2001 – 231 net wells). In addition, during 2003 the Company drilled 440 net stratigraphic test/service wells on the oil sands leases in the Horizon Project and in North Alberta.

North America 2003 drilling was focused in the Company's heavy crude oil areas of North Alberta (315 net wells), its shallow natural gas area in South Alberta (417 net wells) and its natural gas area in Northwest Alberta (98 net wells). North America capital expenditures also included the expansion of the Company's Primrose properties, where 41 wells were drilled in 2003. Steaming commenced in early 2004 and production from these wells is expected in mid-2004.

North America capital expenditures include the acquisition of the West Stoddart natural gas plant. The West Stoddart natural gas plant is located 50 kilometres northwest of Fort St. John, British Columbia and has a processing capacity of 120 mmcf/d.

Capital expenditures also included work on the Horizon Project, where the DBM was completed. The Company also completed construction work on the access road and three bridges. Work on the EDS, the third and final stage of engineering work, has commenced and is expected to be completed by mid-2004. The Alberta Energy and Utilities Board and Alberta Environment, in co-operation with other provincial and federal regulatory agencies, have deemed the application for the Horizon Project as being complete.

In 2003, North Sea capital expenditures included the drilling of 18 wells focusing on targeting reserves stranded against faults within the Ninian and Murchison Fields. The Company further consolidated its ownership interests to 87.6% in the Banff Field, located in the Central North Sea, by acquiring an additional 31.7% working interest and assuming operatorship. In addition, the Company was the successful bidder on six new exploration licenses at the UK Government's 21st Seaward Licensing Round. These blocks provide for additional exploration lands adjacent to the Ninian hub in the northern North Sea. In 2003, a satellite pool was drilled off the Murchison platform but encountered no hydrocarbons and an unsuccessful exploration well was drilled offshore France.

Offshore West Africa capital expenditures included the continued development of the Espoir Field located offshore Côte d'Ivoire with the perforation of the upper zone of the East Espoir structure during the second quarter of 2003. Also in the second quarter of 2003, a successful well was drilled in the Acajou satellite pool. Development of the Baobab Field continues with four major contracts being awarded in 2003 for the drilling; supply of subsea Xmas trees, manifolds, flowlines, controls and associated equipment; supply of pipelines, risers and installation of all of the subsea equipment; and the supply and operation of a floating production, storage and offtake vessel. The drilling of the water injection and production wells commenced in the fourth quarter of 2003 and production from the Baobab Field is expected to commence in mid-2005. Construction of the floating production, storage and offtake vessel is currently underway. In 2003, the first of several potential exploration targets located on Block 16, offshore Angola was drilled. The well, Zenza-1, in which the Company has a 50% working interest, was drilled for a total cost of US$17 million, and although the well encountered reservoir quality sands and shows of hydrocarbons, it was not in sufficient amounts to be commercial. Accordingly, the well has been plugged and abandoned. The results of the well will be integrated into the geological model for Block 16 and a second exploratory well will be drilled in 2005.

Environment

The Company's environmental management plan and operating guidelines focus on minimizing the impact of field operations while meeting regulatory requirements and corporate standards. The Company, as part of this plan, has implemented a proactive program that includes:

- An annual internal environmental compliance audit and inspection program of our operating facilities;
- An aggressive suspended well inspection program to support future development or eventual abandonment;
- Appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment;
- An effective surface reclamation program;
- A progressive due diligence program related to groundwater monitoring;
- A rigorous program related to preventing and reclaiming spill sites;
- A solution gas reduction and conservation program; and
- A program to replace all fresh water for steaming with brackish water.

The Company has also established stringent operating standards in four areas:

- Using water-based, environmentally friendly drilling muds whenever possible;
- Implementing cost effective ways of reducing greenhouse natural gas emissions per unit of production;
- Exercising care with respect to all waste produced through effective waste management plans; and
- Minimizing produced water volumes onshore and offshore through cost-effective measures.

In 2003, the Company's capital expenditures included $40 million of abandonment expenditures, down from $43 million in 2002 (2001 – $10 million).

Estimated future site restoration liability ($ millions)	**2003**	2002
North America	**$ 1,491**	$ 1,206
North Sea	**764**	745
Offshore West Africa	**26**	35
	2,281	1,986
North Sea PRT recovery	**(331)**	(305)
	$ 1,950	$ 1,681

The estimate of the future site restoration liability is based on estimates of future costs to abandon and restore the wells, production facilities and offshore production platforms. There are numerous factors that affect these costs including such things as the number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs and technology in accordance with present legislation and industry practice. It is important to note that the future abandonment costs to be incurred by the Company in the North Sea will result in an estimated recovery of PRT of $331 million (2002 – $305 million), as abandonment costs are an allowable deduction in determining PRT and may be carried back to reclaim PRT previously paid. The PRT recovery reduces the net abandonment liability of the Company to $1,950 million (2002 – $1,681 million). The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production, lowering costs and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates.

Kyoto Protocol

In December 2002, the Canadian Federal Government ratified the Kyoto Protocol ("Kyoto"). The Company continues to work with departments of the Federal and Provincial governments as legislation and regulatory mechanisms to address the issue of climate change develop. There continues to be uncertainty about the ratification of Kyoto, as certain countries have not yet committed to this treaty. The Company plans to proceed on the assumption that new Canadian legislative and regulatory climate change frameworks will be implemented regardless of the fate of Kyoto. The Federal Government has addressed the uncertainty around the ratification and implementation of Kyoto by providing the oil and gas sector with limits on the cost for large industrial emitters until 2012. For long-term, capital intensive investments, such as the Horizon Project, it is essential for the Company to understand the cost implications associated with the climate change policies beyond 2012. To address these concerns, the Federal Government outlined eight principles that would guide them in its negotiations and policies for the post 2012 years. On the basis of these principles, the Company will continue to work on the development plan of the Horizon Project. Accordingly, the Company will continue to develop strategies that will enable it to deal with the risks and opportunities associated with new climate change policies. In addition, the Company will work with relevant parties to ensure that new policies encourage innovation, energy efficiency, targeted research and development while not impacting Canada's competitive position.

Oil and natural gas reserves

The Company retains qualified independent petroleum engineering consultants, Sproule Associates Limited ("Sproule"), to evaluate 100% of the Company's proved and probable crude oil and natural gas reserves and prepare Evaluation Reports on the Company's total reserves. The Company has been granted an exemption from the recently adopted National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") which prescribes standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. The primary difference between the two standards is the additional requirement under NI 51-101 to disclose proved and probable reserves and future net revenues using forecast prices and costs. The Company has elected to disclose proved reserves using constant prices and costs as mandated by the SEC and has also provided proved and probable reserves under the same parameters as voluntary additional information. Another difference between the two standards is in the definition of proved reserves. As discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards which NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the NI 51-101 and SEC standards is not material.

The Company's Reserves Committee has met with Sproule and carried out independent due diligence procedures with Sproule as to the Company's reserves.

Additional reserve disclosure is contained in the supplementary oil and gas information and the Company's Annual Information Form.

Subsequent event

In February 2004, the Company announced the acquisition of certain resource properties in its North Alberta core region, collectively known as the Petrovera Partnership ("Petrovera"), for $467 million. Current production from the acquired properties is approximately 27,500 bbl/d of heavy oil and 9 mmcf/d of natural gas. Strategically, the acquisition fits with the Company's objective of dominating its core areas and related infrastructure. The Company expects to achieve operating cost reductions through synergies with its existing facilities including additional throughput in its 100% owned ECHO Pipeline.

Risks and uncertainties

The Company is exposed to several operational risks inherent in exploring, developing, producing and marketing crude oil and natural gas. These inherent risks include: economic risk of finding and producing reserves at a reasonable cost; financial risk of marketing reserves at an acceptable price given current market conditions; cost of capital risk associated with securing the needed capital to carry out the Company's operations; risk of fluctuating foreign exchange rates; risk of carrying out operations with minimal environmental impact; risk of governmental policies, social instability or other political, economic or diplomatic developments in its international operations; and credit risk of non-payment for sales contracts or non-performance by counterparties to contracts.

The Company uses a variety of means to help minimize these risks. The Company maintains a comprehensive insurance program to reduce risk to an acceptable level and to protect it against significant losses. Operational control is enhanced by focusing efforts on large core regions with high working interests and by assuming operatorship of all key facilities. Product mix is diversified, ranging from the production of natural gas to the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Sales of crude oil and natural gas are aimed at various markets to ensure that undue exposure to any one market does not exist. Financial instruments are utilized to help ensure targets are met and to manage commodity prices, foreign currency rates and interest rate exposure. The Company minimizes credit risks by entering into sales contracts and financial derivatives with only highly rated entities and financial institutions. In addition, the Company reviews its exposure to individual companies on a regular basis, and where appropriate ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default.

The Company's current position with respect to its financial instruments is detailed in note 10 to the consolidated financial statements. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

The Company continues to employ an Environmental Management Plan (the "Plan") to ensure the welfare of its employees, the communities in which it operates, and the environment as a whole. Environmental protection is of fundamental importance and is undertaken in accordance with guiding principles approved by the Company's Board of Directors. A detailed copy of the Company's Plan is presented to, and reviewed by, the Board of Directors annually. The Plan is updated quarterly at the Directors' meetings.

Critical accounting estimates

Management is often required to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. A comprehensive discussion of the Company's significant accounting policies is contained in note 1 to the consolidated financial statements. The following is a discussion of the accounting estimates that are critical in determining the Company's financial results.

Full cost accounting

The Company follows the full cost method of accounting for oil and natural gas properties and equipment as prescribed by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, all costs relating to the exploration for and development of oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. The capitalized costs and future capital costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country. Capitalized costs in each cost centre may not exceed the sum of undiscounted future net revenues from proved properties and the cost of unproved properties, net of provision for impairment, less estimated future financing and administrative expenses and income taxes (the "ceiling test"). If the net capitalized costs of a cost centre are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates, the excess must be charged as an expense against net earnings. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country.

The alternate acceptable method of accounting for oil and natural gas properties and equipment is the successful efforts method. A major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs would be charged against net earnings in the year incurred rather than being capitalized to property, plant and equipment. In addition, under this method cost centres are defined based on reserve pools rather than by country.

Oil and natural gas reserves

The Company retains independent petroleum engineering consultants Sproule to evaluate the Company's proved and probable oil and natural gas reserves. In 2003, Sproule evaluated 100% of the Company's reserves.

The estimation of reserves involves the exercise of judgement. Forecasts are based on engineering data, future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization. A revision to the reserve estimate could result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of oil and natural gas property, plant and equipment under the ceiling test.

Future site restoration

The Company provides for the estimated future dismantlement, site restoration and abandonment costs of oil and natural gas properties using the unit-of-production method. Future site restoration costs for processing and production facilities are provided for using the straight-line method over their estimated lives. The annual provision is included in depletion, depreciation and amortization. The estimated site restoration costs are based on engineering estimates using current costs and technology in accordance with existing legislation and industry practice. The estimation of these costs can be affected by factors such as the number of wells drilled, well depth and area specific environmental legislation. These estimates are reviewed regularly and could impact the DD&A rate used by the Company. A revision to these estimated future costs could result in a higher or lower DD&A expense charged to net earnings.

Stock-based compensation

The Company's Option Plan provides for granting of stock options to directors, officers and employees. Stock options granted under the Option Plan have a maximum term of six years to expiry and vest equally over a five-year period starting on the first anniversary date of the grant. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the day of the grant. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price. In June 2003, the Company approved a modification to its Option Plan. In lieu of receiving common shares, the stock option holder has the right to elect to receive a cash payment equal to the difference between the exercise price of the stock option and the market price of the Company's common shares on the date of surrender, multiplied by the number of common shares covered by the stock options surrendered.

The modification to the Option Plan was accounted for prospectively and for the year ended December 31, 2003, the Company recorded compensation expense of $200 million. As at December 31, 2003, the total liability for expected cash settlements under the Option Plan is $171 million, of which $130 million is included as a current liability. During the year ended December 31, 2003, cash payments of $31 million were made for 1,337,398 stock options surrendered.

New accounting standards

Full cost accounting

In September 2003, the CICA issued Accounting Guideline 16 "Oil and Gas Accounting – Full Cost". The Guideline modifies the ceiling test, which limits the aggregate capitalized costs that may be carried forward to future periods. Specific new guidance was provided on several issues, including the frequency of conducting cost centre impairment tests, the testing for cost centre recoverability and the method of determining fair value. The Guideline recommends that cost centre impairment tests should be conducted at each annual balance sheet date. Recovery of costs is tested by comparing the carrying amount of the oil and natural gas assets to the undiscounted cash flows from those assets using proved reserves and expected future prices and costs. If the carrying amount exceeds the recoverable amount, then impairment should be recognized on the amount by which the carrying amount of the assets exceeds the present value of expected cash flows using proved and probable reserves and expected future prices and costs. The effective date of the Guideline is for fiscal years beginning on or after January 1, 2004, with early adoption recommended. This guideline will apply to the ceiling test relating to the impairment of the Company's property, plant and equipment. Adoption of this standard would not have had an impact on the Company's consolidated financial statements for the year ended December 31, 2003.

Asset retirement obligations

In January 2003, the CICA issued Section 3110 "Asset Retirement Obligations". The Section requires the recognition of the fair value of the retirement obligation for related long-term assets as a liability. Retirement costs equal to the retirement obligation are capitalized as part of the cost of the associated capital asset and amortized to expense through depletion over the life of the asset. In subsequent periods, the liability is adjusted for the passage of time and any changes in the amount or timing of the underlying future cash flows. This standard will be adopted retroactively effective January 1, 2004, and prior period comparative balances will be restated. Adoption of the standard will have the following effects on the Company's financial statements:

($ millions)		January 1, 2004
Consolidated balance sheet		
Increase property, plant and equipment	$	445
Increase asset retirement obligation	$	450
Increase future income tax liability	$	3
Decrease foreign currency translation adjustment	$	(14)
Increase retained earnings	$	6

The Company's pipelines and co-generation plant have indeterminant lives and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligation for these assets will be recorded in the year in which the lives of the assets are determinable.

Hedging relationships

In December 2001, the CICA issued Accounting Guideline 13, "Hedging Relationships". The effective date of this Guideline was deferred to fiscal years beginning on or after July 1, 2003. The Guideline addresses the types of items that qualify for hedge accounting, the formal documentation required to enable the use of hedge accounting and the requirement to evaluate hedges for effectiveness. The Guideline does not specify how hedge accounting should be applied but does require financial instruments that are not designated as hedges be recorded at fair value on the Company's consolidated balance sheet, with changes in fair value recorded in earnings. This Guideline will be adapted prospectively effective January 1, 2004 and will have the following effects on the Company's financial statements:

($ millions)		January 1, 2004
Consolidated balance sheet		
Increase derivative financial instruments asset	$	16
Increase future income tax liability	$	7
Increase deferred revenue	$	9

Outlook

The Company continues its strategy of maintaining a large portfolio of varied projects, which enables the Company over an extended period of time to provide consistent growth in production and high shareholder returns. Annual budgets are developed, scrutinized throughout the year and changed if necessary in the context of project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas.

The Company expects production levels in 2004 to average 1,320 to 1,395 mmcf/d of natural gas and 245,000 to 265,000 bbl/d of crude oil and NGLs, taking into account the Petrovera acquisition. First quarter 2004 production guidance for natural gas is 1,285 to 1,315 mmcf/d of natural gas and 263,000 to 283,000 bbl/d of crude oil and NGLs.

The budgeted capital expenditures in 2004 are currently expected to be as follows:

($ millions)	2004 Budget
North America natural gas	$ 900
North America crude oil and NGLs	550
North Sea crude oil and NGLs	300
Offshore West Africa crude oil and NGLs	290
Property acquisitions and midstream	510
	2,550
Horizon Project (1)	200 – 400
Total	$ 2,750 – 2,950

(1) Expenditure level is dependent upon timing of regulatory and Board of Director approvals.

In 2004, the Company expects to drill approximately 706 net natural gas wells, 274 net crude oil wells and 321 stratigraphic test/service wells. The 2004 North America natural gas program will be highlighted by expanded drilling programs in the Northwest Alberta and Northeast British Columbia core regions as follows:

(number of wells)	2004 Budget
Northeast British Columbia	172
Northwest Alberta	145
North Alberta	183
South Alberta	206
Total	706

The Company continues the disciplined development of its heavy crude oil resources. These reserves will be developed as heavy crude oil markets permit. The 2004 drilling program consists of 110 conventional heavy crude oil wells, 51 thermal heavy crude oil wells, 43 light crude oil wells and 43 Pelican Lake crude oil wells. At Pelican Lake, the Enhanced Oil Recovery waterflood test program was a success and as such, the Company will begin the phased roll out of the waterflood with approximately 20% of the field being under waterflood by the end of 2004. The waterflood will stabilize production, but will require a further 63 Pelican Lake productive wells to be converted from producers to water injectors.

Based upon the capital expenditure budget, the Company expects to incur Canadian current income tax expense in 2004 of $100 to $175 million.

The 100% owned and operated Horizon Project is expected to be built in three phases and produce approximately 232,000 bbl/d of light, sweet synthetic crude oil. In 2004, the third phase of engineering, EDS, is expected to be completed. In addition, the financing plan will be optimized and finalized by the third quarter of 2004. The 2004 capital budget for the Horizon Project will be phased in over the year and is dependent upon regulatory approval and cost estimates. Regulatory review for the environmental assessment of the Horizon Project was conducted in September 2003 and the Company received approval from the review panel in January 2004. Final regulatory approvals are expected in the first half of 2004. With final regulatory approval, the completion of the EDS and confirmation of cost estimates, Board of Director approval will be sought in late 2004. Depending upon the timing of final approval, a total of $200 to $400 million is budgeted for the Horizon Project in 2004. The Company anticipates that 80% of the detailed engineering will be completed before it commits to the construction of the Horizon Project.

The capital budget in 2004 for the North Sea is $300 million and includes the drilling of approximately 13 crude oil wells, implementing a secondary recovery natural gas injection scheme at Banff, optimizing Ninian and Murchison waterfloods, and building on the successful 2003 recompletion program. Average crude oil production is expected to remain relatively consistent with current production levels; however, natural gas volumes will be lower as natural gas sales at Banff are diverted to reinjection.

In 2004, the capital budget for Offshore West Africa is set at $290 million, of which the Company anticipates $220 million to be spent on the continuing development of the Baobab Field in Côte d'Ivoire. The remainder will be spent on the pre-development work associated with the West Espoir development and various exploration activities.

The original budget was based on an average natural gas price of $5.50 per GJ at AECO, an oil price of US$26.00 per bbl for WTI and a heavy oil differential of US$8.50 per bbl. The current price-deck for our products, if maintained, could result in a significant increase in cash flow over the budget. The Company will monitor its expected cash flow excess and intends to allocate a minimum of 50% of such excess towards debt repayment. The remaining excess will be directed to the Company's authorized share buy-back program and additional expenditures on conventional crude oil and natural gas opportunities. Such expenditures will only be incurred as excess cash flows are realized and will be subject to the same economic tests as regular budgeted expenditures. It is expected that the largest portion of the additional capital expenditures will take place late in the third and fourth quarters of 2004 and accordingly will not add materially to the Company's 2004 average production volumes. Should additional economic opportunities for share buy-backs or capital activities not present themselves to the extent allocated, such allocations of excess cash flow would revert to debt repayment.

Sensitivity analysis [1]

	Cash flow from operations [2] ($ millions)	Cash flow from operations [2] ($/share, basic)	Net earnings [2] ($ millions)	Net earnings [2] ($/share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl [3]				
Excluding financial derivatives	$ 88	$ 0.66	$ 63	$ 0.47
Including financial derivatives	$ 65 – 88	$ 0.48 – 0.66	$ 46 – 63	$ 0.34 – 0.47
Natural gas – AECO C$0.10/mcf [3]				
Excluding financial derivatives	$ 35	$ 0.26	$ 21	$ 0.16
Including financial derivatives	$ 32 – 34	$ 0.24 – 0.25	$ 19 – 21	$ 0.14 – 0.16
Volume changes				
Crude oil – 10,000 bbl/d	$ 50	$ 0.37	$ 17	$ 0.12
Natural gas – 10 mmcf/d	$ 13	$ 0.10	$ 5	$ 0.04
Foreign currency rate change				
$0.01 change in C$ in relation to US$ [3]				
Excluding financial derivatives	$ 48	$ 0.36	$ 15	$ 0.11
Including financial derivatives	$ 41 – 44	$ 0.31 – 0.33	$ 10 – 13	$ 0.08 – 0.09
Interest rate change – 1%	$ 10	$ 0.08	$ 10	$ 0.08

(1) The sensitivities are calculated based on 2003 fourth quarter results.

(2) Attributable to common shareholders.

(3) For details of financial instruments in place, see consolidated financial statements note 10.

Daily production by segment, before royalties

	Q1	Q2	Q3	Q4	2003	2002	2001
Crude oil and NGLs (bbl/d)							
North America	173,045	175,232	174,838	176,429	174,895	169,675	166,675
North Sea	56,963	55,781	60,193	54,529	56,869	38,876	36,252
Offshore West Africa	7,552	9,594	11,985	13,304	10,628	6,784	3,396
Total	237,560	240,607	247,016	244,262	242,392	215,335	206,323
Natural gas (mmcf/d)							
North America	1,265	1,278	1,229	1,206	1,245	1,204	906
North Sea	41	40	49	52	46	27	12
Offshore West Africa	4	7	11	12	8	1	–
Total	1,310	1,325	1,289	1,270	1,299	1,232	918
Barrels of oil equivalent (boe/d)							
North America	383,952	388,210	379,751	377,448	382,315	370,337	317,658
North Sea	63,764	62,507	68,323	63,246	64,469	43,391	38,293
Offshore West Africa	8,236	10,738	13,808	15,241	12,030	6,994	3,396
Total	455,952	461,455	461,882	455,935	458,814	420,722	359,347

Per unit results

	Q1	Q2	Q3	Q4	2003	2002	2001
Crude oil and NGLs ($/bbl)							
Sales price	$ 35.26	$ 30.27	$ 30.97	$ 30.02	$ 31.59	$ 29.76	$ 24.31
Royalties	3.56	2.78	2.56	2.22	2.77	3.16	2.17
Production expense	10.79	10.80	10.14	9.45	10.28	8.45	7.64
Netback	$ 20.91	$ 16.69	$ 18.27	$ 18.35	$ 18.54	$ 18.15	$ 14.50
Natural gas ($/mcf)							
Sales price	$ 7.25	$ 6.12	$ 5.50	$ 5.23	$ 6.02	$ 3.76	$ 5.16
Royalties	1.78	1.35	1.11	1.05	1.32	0.78	1.25
Production expense	0.57	0.59	0.63	0.63	0.60	0.57	0.51
Netback	$ 4.90	$ 4.18	$ 3.76	$ 3.55	$ 4.10	$ 2.41	$ 3.40
Barrels of oil equivalent ($/boe)							
Sales price	$ 39.24	$ 33.32	$ 31.94	$ 30.64	$ 33.75	$ 26.25	$ 27.15
Royalties	6.96	5.32	4.46	4.12	5.20	3.91	4.42
Production expense	7.27	7.34	7.17	6.81	7.15	5.99	5.69
Netback	$ 25.01	$ 20.66	$ 20.31	$ 19.71	$ 21.40	$ 16.35	$ 17.04

Netback analysis

($/boe, except daily production)	2003	2002	2001
Daily production, before royalties (boe/d)	**458,814**	420,722	359,347
Sales price	**$ 33.75**	$ 26.25	$ 27.15
Royalties	**5.20**	3.91	4.42
Production expense	**7.15**	5.99	5.69
Netback	**21.40**	16.35	17.04
Midstream contribution	**(0.28)**	(0.25)	(0.12)
Administration	**0.52**	0.40	0.29
Interest	**0.94**	1.03	1.05
Realized foreign exchange loss (gain)	**0.05**	0.02	(0.01)
Taxes other than income tax (current)	**0.69**	0.35	0.53
Current income tax (North Sea)	**0.14**	(0.13)	0.47
Current income tax (Offshore West Africa)	**0.06**	0.04	–
Current income tax (North America)	**0.26**	–	–
Current income tax (Large Corporations Tax)	**0.09**	0.14	0.11
Cash flow	**$ 18.93**	$ 14.75	$ 14.72

Quarterly financial information

($ millions, except per share amounts)	Q1	Q2	Q3	Q4	Total
2003					
Revenue	**$ 1,693**	**$ 1,477**	**$ 1,434**	**$ 1,368**	**$ 5,972**
Cash flow from operations attributable to common shareholders	**$ 906**	**$ 762**	**$ 758**	**$ 734**	**$ 3,160**
Per common share – basic	**$ 6.76**	**$ 5.68**	**$ 5.62**	**$ 5.48**	**$ 23.54**
– diluted	**$ 6.53**	**$ 5.57**	**$ 5.56**	**$ 5.42**	**$ 23.06**
Net earnings attributable to common shareholders	**$ 428**	**$ 525**	**$ 203**	**$ 251**	**$ 1,407**
Per common share – basic	**$ 3.19**	**$ 3.91**	**$ 1.51**	**$ 1.87**	**$ 10.48**
– diluted	**$ 3.03**	**$ 3.78**	**$ 1.49**	**$ 1.83**	**$ 10.14**
2002					
Revenue	$ 782	$ 924	$ 1,239	$ 1,397	$ 4,342
Cash flow from operations attributable to common shareholders	$ 359	$ 475	$ 643	$ 777	$ 2,254
Per common share – basic	$ 2.95	$ 3.86	$ 4.83	$ 5.81	$ 17.63
– diluted	$ 2.85	$ 3.70	$ 4.71	$ 5.62	$ 16.99
Net earnings attributable to common shareholders	$ 99	$ 145	$ 117	$ 209	$ 570
Per common share – basic	$ 0.81	$ 1.18	$ 0.88	$ 1.56	$ 4.46
– diluted	$ 0.79	$ 1.09	$ 0.86	$ 1.51	$ 4.31

Trading and share statistics

	Q1	Q2	Q3	Q4	2003 Total	2002 Total
TSX – C$						
Trading volume (thousands)	**45,742**	**36,859**	**30,386**	**34,688**	**147,675**	154,829
Share price ($/share)						
High	**$ 52.90**	**$ 57.39**	**$ $ 57.29**	**$ 67.22**	**$ 67.22**	$ 54.54
Low	**$ 45.20**	**$ 46.55**	**$ $ 51.23**	**$ 53.31**	**$ 45.20**	$ 37.60
Close	**$ 50.15**	**$ 53.75**	**$ $ 55.59**	**$ 65.37**	**$ 65.37**	$ 46.80
Market capitalization at December 31 ($ millions)					**$ 8,742**	$ 6,261
Shares outstanding (thousands)					**133,731**	133,776
NYSE – US$						
Trading volume (thousands)	**2,539**	**2,546**	**2,760**	**3,884**	**11,729**	7,966
Share price ($/share)						
High	**$ 35.97**	**$ 42.45**	**$ 41.35**	**$ 51.39**	**$ 51.39**	$ 34.88
Low	**$ 29.25**	**$ 31.51**	**$ 36.50**	**$ 40.44**	**$ 29.25**	$ 23.55
Close	**$ 34.00**	**$ 39.91**	**$ 41.16**	**$ 50.44**	**$ 50.44**	$ 29.67
Market capitalization at December 31 ($ millions)					**$ 6,745**	$ 3,969
Shares outstanding (thousands)					**133,731**	133,776

Management's report and auditors' report

Management's report

The accompanying consolidated financial statements and all information in the annual report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies in the notes to the consolidated financial statements. Where necessary, management has made informed judgements and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with Canadian generally accepted accounting principles appropriate in the circumstances. The financial information elsewhere in the annual report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to examine the consolidated financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the consolidated financial statements.

The Board of Directors (the "Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board exercises this responsibility through the Audit Committee of the Board. This committee, which is comprised of non-management directors, meets with management and the external auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board for approval. The consolidated financial statements have been approved by the Board on the recommendation of the Audit Committee.

Randall Davis

John G. Langille CA
President & Director

Douglas A. Proll CA
Senior Vice President, Finance

Randall S. Davis CA
Financial Controller
February 19, 2004

Auditors' report

To the Shareholders of Canadian Natural Resources Limited,

We have audited the consolidated balance sheets of Canadian Natural Resources Limited as at December 31, 2003 and 2002 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three year period ended December 31, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta, Canada
February 19, 2004

Consolidated financial statements

Consolidated balance sheets

As at December 31 (millions of Canadian dollars)		2003		2002
ASSETS				
Current assets				
Cash	$	**104**	$	30
Accounts receivable and other		**751**		745
		855		775
Property, plant and equipment (note 2)		**13,269**		12,500
Deferred charges		**74**		84
	$	**14,198**	$	13,359
LIABILITIES				
Current liabilities				
Accounts payable	$	**464**	$	337
Accrued liabilities		**712**		428
Current portion of long-term debt (note 3)		**184**		24
		1,360		789
Long-term debt (note 3)		**2,645**		4,074
Deferred credits (note 4)		**488**		440
Future income tax (note 5)		**3,588**		3,188
		8,081		8,491
SHAREHOLDERS' EQUITY				
Preferred securities (note 6)		**103**		126
Share capital (note 7)		**2,353**		2,304
Retained earnings		**3,644**		2,414
Foreign currency translation adjustment (note 8)		**17**		24
		6,117		4,868
	$	**14,198**	$	13,359

Commitments (note 11)

Signed on behalf of the Board:

Ambassador Gordon D. Giffin
Chairman of the Audit Committee
and Director

N. Murray Edwards
Vice-Chairman of the Board of Directors
and Director

Consolidated statements of earnings

For the years ended December 31 (millions of Canadian dollars, except per common share amounts)	2003	2002	2001
Revenue	**$ 5,972**	$ 4,342	$ 3,757
Less: royalties	**(872)**	(600)	(580)
	5,100	3,742	3,177
Expenses			
Production	**1,209**	931	756
Transportation	**262**	262	170
Depletion, depreciation and amortization	**1,565**	1,314	903
Administration	**87**	61	38
Stock-based compensation (note 7)	**200**	–	–
Interest	**157**	159	138
Foreign exchange (gain) loss	**(312)**	(31)	63
Loss on sale of United States assets (note 2)	**–**	–	24
	3,168	2,696	2,092
Earnings before taxes	**1,932**	1,046	1,085
Taxes other than income tax (note 5)	**107**	63	69
Current income tax (note 5)	**92**	8	77
Future income tax (note 5)	**339**	400	283
Net earnings	**1,394**	575	656
Dividend on preferred securities, net of tax	**(5)**	(6)	(6)
Revaluation of preferred securities, net of tax	**18**	1	(8)
Net earnings attributable to common shareholders	**$ 1,407**	$ 570	$ 642
Net earnings attributable to common shareholders per common share (note 9)			
Basic	**$ 10.48**	$ 4.46	$ 5.30
Diluted	**$ 10.14**	$ 4.31	$ 5.17

Consolidated statements of retained earnings

For the Years Ended December 31 (millions of Canadian dollars)	2003	2002	2001
Balance – beginning of year	**$ 2,414**	$ 1,908	$ 1,391
Net earnings	**1,394**	575	656
Dividend on preferred securities, net of tax	**(5)**	(6)	(6)
Revaluation of preferred securities, net of tax	**18**	1	(8)
Dividend on common shares (note 7)	**(81)**	(64)	(49)
Purchase of common shares (note 7)	**(96)**	–	(76)
Balance – end of year	**$ 3,644**	$ 2,414	$ 1,908

Consolidated statements of cash flows

For the years ended December 31 (millions of Canadian dollars)	2003	2002	2001
Operating activities			
Net earnings	**$ 1,394**	$ 575	$ 656
Non-cash items			
Depletion, depreciation and amortization	**1,565**	1,314	903
Stock-based compensation	**200**	–	–
Unrealized foreign exchange (gain) loss	**(320)**	(35)	64
Deferred petroleum revenue tax	**(9)**	10	–
Future income tax	**339**	400	283
Loss on sale of United States assets	**–**	–	24
Cash flow provided from operations	**3,169**	2,264	1,930
Deferred charges	**10**	(84)	–
Net change in non-cash working capital (note 12)	**(48)**	(157)	(42)
	3,131	2,023	1,888
Financing activities			
Repayment of bank credit facilities	**(647)**	(1,234)	(442)
Repayment of senior unsecured notes	**(85)**	(16)	(16)
Issue of US dollar debt securities	**–**	1,749	615
Repayment of obligations under capital leases	**(8)**	(4)	–
Repayment of limited recourse loan	**–**	–	(12)
Dividend on preferred securities	**(9)**	(10)	(10)
Dividend on common shares	**(77)**	(60)	(36)
Issue of common shares on exercise of stock options	**89**	84	43
Purchase of common shares	**(144)**	–	(113)
Net change in non-cash working capital (note 12)	**(11)**	27	7
	(892)	536	36
Investing activities			
Business combination, net of cash acquired (note 13)	**–**	(843)	–
Expenditures on property, plant and equipment	**(2,526)**	(1,752)	(1,948)
Net proceeds on sale of property, plant and equipment	**20**	76	63
Net expenditures on property, plant and equipment	**(2,506)**	(2,519)	(1,885)
Net change in non-cash working capital (note 12)	**341**	(25)	(52)
	(2,165)	(2,544)	(1,937)
Increase (decrease) in cash	**74**	15	(13)
Cash – beginning of year	**30**	15	28
Cash – end of year	**$ 104**	$ 30	$ 15

Supplemental disclosure of cash flow information (note 12)

1. Accounting policies

Canadian Natural Resources Limited (the "Company") is a senior independent oil and natural gas exploration, development and production company based in Calgary, Alberta, Canada. The Company's operations are focused in North America, largely in western Canada, the North Sea and Offshore West Africa.

Within western Canada, the Company is developing its Horizon Oil Sands Project (the "Horizon Project") and maintains its midstream activities. The Horizon Project involves a plan to recover bitumen through mining operations, while the midstream activities include the Company's pipeline operations and an electricity co-generation system.

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada. A summary of differences between accounting principles in Canada and those generally accepted in the United States ("US") is contained in note 16.

Significant accounting policies are summarized as follows:

Principles of consolidation

The consolidated financial statements include the accounts of the Company and all of its subsidiaries and partnerships. A significant portion of the Company's activities are conducted jointly with others and the consolidated financial statements reflect only the Company's proportionate interest in such activities.

Measurement uncertainty

Management has made estimates and assumptions regarding certain assets, liabilities, revenues and expenses in the preparation to the consolidated financial statements. Such estimates primarily relate to unsettled transactions and events as of the date to the consolidated financial statements. Accordingly, actual results may differ from estimated amounts.

Depletion, depreciation and amortization and amounts used for ceiling test calculations are based on estimates of proved oil and natural gas reserves and commodity prices, production expenses and capital costs required to develop and produce those reserves. The majority of the Company's reserve estimates are evaluated annually by independent engineering firms. By their nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could be material.

The measurement of petroleum revenue tax expense and the related provision in the consolidated financial statements are subject to uncertainty associated with future recoverability of oil and natural gas reserves, commodity prices and the timing of future events, which could result in material changes to deferred amounts.

Cash

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with a term to maturity of three months or less from the transaction date are reported as cash equivalents.

Property, plant and equipment

The Company follows the full cost method of accounting for oil and natural gas properties and equipment as prescribed by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, all costs relating to the exploration for and development of oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. Administrative overhead incurred during the development phase of large capital projects is capitalized until commercial production commences. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country.

All costs associated with the Horizon Project during its development stage are capitalized.

Depletion, depreciation and amortization

The costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country. Volumes of net production and net reserves before royalties are converted to equivalent units on the basis of estimated relative energy content. In determining its depletion base, the Company includes estimated future costs to be incurred in developing proved reserves and excludes the cost of unproved properties. The unproved properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the value of the unproved property is considered to be impaired, the cost of the unproved property or the amount of the impairment is added to costs subject to depletion. Certain costs in cost centres from which there has been no commercial production are not subject to depletion until commercial production commences.

Processing and production facilities are depreciated on a straight-line basis over their estimated lives.

The Company carries its oil and natural gas properties at the lower of net capitalized cost and net recoverable amount (the "ceiling test"). The net capitalized cost of each cost centre is calculated as the net book value of the related assets less the accumulated provisions for future income taxes and future site restoration. Net recoverable amount is limited to the sum of undiscounted future net revenues from proved properties and the cost of unproved properties net of provisions for impairment less estimated future financing and administrative expenses and income taxes. Future net revenues are based on sales prices and costs prevailing at year end.

The Company carries its midstream assets at the lower of net capitalized cost and fair value. Midstream assets are depreciated on a straight-line basis over their estimated lives.

Head office capital assets are amortized on a declining balance basis over their estimated useful lives.

Deferred charges

Deferred charges include deferred financing costs associated with the issuance of long-term debt and settlement costs of long-term natural gas contracts. Deferred charges are amortized over the original term of the related instrument.

Future site restoration

Estimated future dismantlement, site restoration and abandonment costs ("site restoration costs") for oil and natural gas properties are provided for using the unit-of-production method. Future site restoration costs for processing and production facilities are provided for on a straight-line basis over their estimated lives. The estimated site restoration costs are based on engineering estimates using current costs and technology in accordance with current legislation and industry practice. The annual provision is included in depletion, depreciation and amortization. Actual site restoration costs incurred to dismantle the processing and production facilities and restore well sites are charged against the related future site restoration liability.

Foreign currency translation

Foreign operations that are self-sustaining are translated using the current rate method. Under this method, assets and liabilities are translated to Canadian dollars from their functional currency using the exchange rate in effect at the consolidated balance sheet date. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Gains or losses on translation are included in the foreign currency translation adjustment in shareholders' equity in the consolidated balance sheets.

Foreign operations that are integrated are translated using the temporal method. For foreign currency balances and integrated subsidiaries, monetary assets and liabilities are translated to Canadian dollars at the exchange rate in effect at the consolidated balance sheet date and non-monetary assets and liabilities are translated at the rate of exchange in effect when the assets were acquired or obligations incurred. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Provisions for depletion, depreciation and amortization are translated at the same rate as the related items.

Gains or losses on the translation of long-term debt denominated in US dollars are either recognized in net earnings immediately, or in the foreign currency translation adjustment (note 8) for translation gains or losses on that portion of the US dollar denominated debt designated as a hedge of self-sustaining foreign operations

Petroleum revenue tax

The Company accounts for future United Kingdom petroleum revenue tax ("PRT") by the life-of-the-field method. The total future liability or recovery of PRT is estimated using current sales prices and costs. The estimated future PRT is apportioned to accounting periods on the basis of total estimated future revenues. Changes in the estimated total future PRT are accounted for prospectively.

Production sharing contract

Production generated from offshore Côte d'Ivoire is shared by the terms of the Production Sharing Contract ("PSC") with the State Oil Company of Côte d'Ivoire ("Petroci"). Revenues are divided into cost recovery revenues and profit revenues. Cost recovery revenues allow the Company to recover the capital and operating costs carried by the Company on behalf of Petroci. These revenues are reported as sales revenues. Profit revenues are allocated to joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Côte d'Ivoire Government. The Government's share of revenues attributable to the Company's equity interest is reported as either a royalty expense or a current tax expense in accordance with the PSC.

Income tax

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted on the consolidated balance sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in net earnings in the period of the change.

Revenue recognition

Revenues are recognized when products have been delivered or services have been performed.

Stock-based compensation plans

As a result of modifications to its Stock Option Plan (note 7) in the second quarter of 2003, the Company prospectively adopted the following accounting policy with respect to stock-based compensation:

The Company accounts for its stock-based compensation using the intrinsic value method. A liability for expected cash settlements under the Company's Stock Option Plan (the "Option Plan) is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares. The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the net change is recognized in net earnings. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by employees, officers or directors and the previously recognized liability associated with the stock options is recorded as share capital.

The Company also has an employee stock savings plan. Contributions to the employee stock savings plan are recorded as compensation expense at the time of the contribution.

Financial instruments

Financial instruments are utilized by the Company to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. The Company's policy is to formally document relationships between hedging instruments and hedged items, the risk management objective, and the strategy for undertaking various hedge transactions. The Company assesses whether the financial instruments entered into are highly effective as fair value or cash flow hedges, both at the inception of the hedge and over the term of the financial instrument.

The Company enters into commodity price contracts to hedge anticipated sales of oil and natural gas production in order to protect cash flow for capital expenditure programs. Gains or losses on these contracts are included in oil and natural gas revenue at the time of sale of the related product. Foreign exchange translation gains and losses on foreign currency denominated financial instruments used to hedge anticipated US dollar denominated oil and natural gas sales are recognized in revenue at the time of sale of the related product.

The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap agreements require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Gains or losses on these financial instruments are included in interest expense in the consolidated statement of earnings when realized. The related amount receivable from or payable to counterparties is included as an adjustment to accrued interest in the consolidated balance sheets. The Company assumed, through the Rio Alto acquisition, a foreign currency swap agreement that hedges a foreign currency denominated long-term debt instrument through an offsetting forward exchange contract. The foreign exchange translation gains and losses on the financial instrument are used to offset the respective translation gains and losses recognized on the long-term debt.

Realized gains and losses on the termination of financial instruments that have been accounted for as hedges are deferred under non-current assets or liabilities on the consolidated balance sheets and recognized in net earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized gain or loss is recognized in net earnings.

Per common share amounts

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. This method assumes that proceeds received from the exercise of in-the-money stock options not included as a liability and other dilutive instruments are used to purchase common shares at the average market price during the year.

Comparative figures

Certain figures provided for prior years have been reclassified to conform to the presentation adopted in 2003.

In accordance will EIC 123 "Reporting Revenue Gross as a Principal Versus Net as an Agent" of the Emerging Issues Committee of the CICA, transportation costs are no longer netted against revenue but are disclosed as a separate expense in the consolidated statements of earnings.

2. Property, plant and equipment

		2003	
	Cost	Accumulated depletion and depreciation	Net
Oil and natural gas			
North America	$ 15,632	$ 4,791	$ 10,841
North Sea	1,642	485	1,157
Offshore West Africa	788	137	651
Horizon Project	381	–	381
Midstream	225	25	200
Head office	70	31	39
	$ 18,738	$ 5,469	$ 13,269

		Cost		2002 Accumulated depletion and depreciation		Net
Oil and natural gas						
North America	$	13,863	$	3,611	$	10,252
North Sea		1,621		344		1,277
Offshore West Africa		612		94		518
Horizon Project		229		–		229
Midstream		214		18		196
Head office		50		22		28
	$	16,589	$	4,089	$	12,500

During the year ended December 31, 2003, the Company capitalized administrative overhead of $12 million (2002 – $13 million, 2001 – $7 million) relating to exploration and development in the North Sea and Offshore West Africa and $23 million (2002 – $4 million, 2001 – $nil) relating to the Horizon Project in North America. During 2001, the Company sold a large portion of its properties in the United States and recorded a loss on sale of $24 million.

Included in property, plant and equipment are unproved land and projects under development that are not subject to depletion or depreciation:

		2003		2002
Oil and natural gas				
North America	**$**	**789**	$	667
North Sea		**56**		62
Offshore West Africa		**237**		132
Horizon Project		**381**		229
	$	**1,463**	$	1,090

3. Long-term debt

		2003		2002
Bank credit facilities				
Bankers' acceptances	**$**	**–**	$	728
US dollar bankers' acceptances (2003 – US$207 million, 2002 – US$150 million)		**268**		237
Medium-term notes				
6.85% unsecured debentures due May 28, 2004		**125**		125
7.40% unsecured debentures due March 1, 2007		**125**		125
Senior unsecured notes				
6.95% due September 30, 2003 (2003 – US$nil, 2002 – US$10 million)		**–**		16
6.42% due May 27, 2004 (US$40 million)		**52**		63
7.69% due December 19, 2005 (US$125 million)		**194**		194
6.50% due May 1, 2008 (2003 – US$nil , 2002 – US$50 million)		**–**		79
Adjustable rate due May 27, 2009 (US$93 million)		**120**		146
US dollar debt securities				
6.70% due July 15, 2011 (US$400 million)		**517**		632
5.45% due October 1, 2012 (US$350 million)		**452**		553
7.20% due January 15, 2032 (US$400 million)		**517**		632
6.45% due June 30, 2033 (US$350 million)		**452**		553
Obligations under capital leases		**7**		15
		2,829		4,098
Less: current portion of long-term debt		**184**		24
	$	**2,645**	$	4,074

Bank credit facilities

The Company has unsecured bank credit facilities of $1,925 million, comprised of a $100 million operating demand facility and a revolving credit and term loan facility of $1,825 million. The revolving credit and term loan facility is fully revolving for 364-day periods with an initial term to June 2004 and a provision for extension at the mutual agreement of the Company and the lenders. If not extended, the facility converts to a non-revolving loan with a term of two years. The full amount of the outstanding principal would be repayable at the end of year two following the initiation of the term period. The facility provides that the borrowings may be made by way of operating advances, prime loans, bankers' acceptances, US base rate loans or US dollar LIBOR advances, which bear interest at the bank's prime rates or at money market rates plus applicable margins. During the year, the Company repaid and cancelled a $500 million acquisition term credit facility.

The weighted average interest rate of bank credit facilities outstanding at December 31, 2003, was 2.32% (2002 – 3.37%).

In addition to the outstanding debt, letters of credit aggregating $69 million have been issued.

Medium-term notes

In August 2003, the Company filed a short form shelf prospectus that allows for the issue of up to $1 billion of medium term notes in Canada until September 2005. If issued, these securities will bear interest as determined at the date of issuance. The Company has $250 million of unsecured debentures outstanding from a previous medium-term note program.

Senior unsecured notes

The final principal repayment on the 6.95% senior unsecured notes was made September 30, 2003. The 6.42% senior unsecured notes are due in full May 27, 2004. In May 2003, the Company prepaid the US$50 million 6.50% senior unsecured notes due May 1, 2008. The adjustable rate senior unsecured notes bear interest at 6.54% increasing to 6.64% under certain circumstances, and have annual principal repayments of US$31 million commencing on May 27, 2007, through May 27, 2009. These debt instruments contain covenants pertaining to the Company's net worth, certain financial ratios and the ability to grant security.

On July 1, 2002, as part of the Rio Alto acquisition, the Company assumed US$125 million of senior unsecured notes maturing December 19, 2005, bearing interest at 7.69%. Through a currency swap, the interest and principal repayment amounts are fixed at 7.30% and $194 million, respectively (note 10).

US dollar debt securities

In May 2003, the Company filed a short form prospectus that allows for the issue of up to US$2 billion of debt securities in the United States until June 2005. If issued, these securities will bear interest as determined at the date of issuance.

On September 16, 2002, the Company issued US$350 million of US dollar debt securities maturing October 1, 2012, bearing interest at 5.45% and US$350.0 million of US dollar debt securities maturing June 30, 2033, bearing interest at 6.45%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. Subsequently, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate on the securities due October 1, 2012 (note 10).

On January 23, 2002, the Company issued US$400 million of US dollar debt securities, maturing January 15, 2032, bearing interest at 7.20%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. Subsequently, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate for a portion of the term (note 10).

Obligations under capital leases

The obligations under capital leases bear interest at an average interest rate of 6.89% and are secured by the related assets.

Required debt repayments

Required debt repayments are as follows:

Year	Repayment
2004	$ 184
2005	$ 194
2006	$ –
2007	$ 165
2008	$ 40
Thereafter	$ 1,978

No debt repayments are reflected for the bank credit facilities due to the extendable nature of the facilities.

4. Deferred credits

	2003	2002
Future site restoration	**$ 447**	$ 440
Stock-based compensation	**41**	–
	$ 488	$ 440

Future site restoration

At December 31, 2003, the Company's total estimated future site restoration costs were $2,281 million (2002 – $1,986 million, 2001 – $1,081 million). These costs are accrued over the life of the Company's proved reserves. Effective January 1, 2004, the Company will adopt the CICA's new accounting standard for asset retirement obligations (note 16).

	2003	2002
Future site restoration		
Balance – beginning of year	**$ 440**	$ 194
Future site restoration provision	**104**	67
Current year expenditures	**(40)**	(34)
Acquisitions and dispositions	**–**	211
Foreign exchange	**(57)**	2
Balance – end of year	**$ 447**	$ 440

Stock-based compensation

In June 2003, the Company modified its Option Plan (note 7), resulting in the recognition of a liability for the expected cash settlements under the Option Plan. The current portion represents the amount of the liability that may be realized within the next 12 month period if all vested options are surrendered for cash settlement.

	2003
Stock-based compensation	
Balance – beginning of year	**$ –**
Stock-based compensation provision	**200**
Current year payment for options surrendered	**(31)**
Transferred to common shares	**(8)**
Capitalized with respect to Horizon Project	**10**
Balance – end of year	**171**
Less: current portion of stock-based compensation	**130**
	$ 41

5. Taxes

Taxes other than income tax	2003	2002	2001
Current petroleum revenue tax	**$ 106**	$ 41	$ 59
Deferred petroleum revenue tax	**(9)**	10	–
Provincial capital taxes and surcharges	**10**	11	9
Other	**–**	1	1
	$ 107	$ 63	$ 69

Income tax

The provision for income tax is as follows:

	2003	2002	2001
Current income tax expense			
Current income tax – North America	**$ 43**	$ –	$ –
Large Corporations Tax – North America	**16**	21	15
Current income tax – North Sea	**23**	(19)	62
Current income tax – Offshore West Africa	**10**	6	–
	92	8	77
Future income tax expense	**339**	400	283
Income tax	**$ 431**	$ 408	$ 360

The provision for income tax is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the difference are as follows:

	2003	2002	2001
Canadian statutory income tax rate	**41.1%**	42.4%	42.8%
Income tax provision at statutory rate	**$ 794**	$ 444	$ 464
Effect on income taxes of:			
Non-deductible portion of Canadian crown payments	**285**	211	201
Canadian resource allowance	**(281)**	(243)	(219)
Large Corporations Tax	**16**	21	15
Deductible UK petroleum revenue tax	**(40)**	(22)	(25)
Foreign tax rate differentials	**20**	(1)	(19)
Federal income tax rate reductions	**(247)**	–	–
Provincial income tax rate reductions	**(31)**	(21)	(63)
UK income tax rate increase	**–**	34	–
Non-taxable portion of foreign exchange	**(99)**	(22)	21
Other	**14**	7	(15)
Income tax	**$ 431**	$ 408	$ 360

The following table summarizes the temporary differences that give rise to the future income tax liability:

	2003	2002
Future income tax liabilities		
Property, plant and equipment	**$ 2,701**	$ 2,656
Timing of partnership items	**1,095**	737
Foreign exchange gain on long-term debt	**90**	–
Other	**14**	14
Future income tax assets		
Future site restoration	**(185)**	(161)
Attributed Canadian Royalty Income	**(58)**	(54)
Stock-based compensation	**(56)**	–
Deferred petroleum revenue tax	**(13)**	(4)
Future income tax liability	**$ 3,588**	$ 3,188

A significant portion of the Company's North American taxable income is generated by partnerships. Income taxes are incurred on the partnerships' taxable income in the year following their inclusion in the Company's consolidated net earnings.

During 2003, the Government of Alberta passed legislation to reduce its corporate income tax rate by 0.5% effective April 1, 2003. Also during 2003, the Canadian federal government passed legislation to change the taxation of resource income. The legislation reduces the corporate income tax rate on resource income from 28% to 21% over five years beginning January 1, 2003. Over the same period, the deduction for resource allowance is phased out and a deduction for actual crown royalties paid is phased in. The Company's future income tax liability was reduced by $31 million with respect to the Alberta corporate income tax rate reduction and by $247 million with respect to the Federal resource income tax rate changes.

6. Preferred securities

The US$80 million preferred securities are in the form of 8.30% subordinated notes. Principal repayments of US$27 million are required annually commencing June 25, 2009. The securities may be prepaid at the option of the Company at any time. The prepaid amount is subject to certain adjustments to compensate holders for any potential loss of return over the original life of the securities, based on market conditions at that time. The notes are subordinated to the long-term debt of the Company and contain, among other things, certain financial covenants restricting the granting of security for new borrowings and the maintenance of specified financial ratios.

The Company has the unrestricted right to pay dividends, principal and principal prepayment amounts by delivering common shares to the Trustee of the preferred securities. Accordingly, the preferred securities are classified as shareholders' equity in the consolidated balance sheets. Dividend payments, net of tax, are charged directly to retained earnings. The semi-annual dividend payments may be deferred at the option of the Company for up to two consecutive periods, with a maximum of eight deferral periods over the life of the securities.

7. Share capital

Authorized

200,000 Class 1 preferred shares with a stated value of $10.00 each.
Unlimited number of common shares without par value.

Issued

Common shares	2003 Number of shares (thousands)	2003 Amount	2002 Number of shares (thousands)	2002 Amount
Balance – beginning of year	**133,776**	**$ 2,304**	121,201	$ 1,698
Issued upon exercise of stock options	**2,690**	**89**	2,523	82
Previously recognized liability on stock options exercised for common shares	**–**	**8**	–	–
Purchase of common shares under Normal Course Issuer Bid	**(2,735)**	**(48)**	–	–
Issued upon acquisition of Rio Alto	**–**	**–**	10,008	522
Issue of flow-through shares, net of tax	**–**	**–**	60	2
Cancellation of common shares	**–**	**–**	(16)	–
Balance – end of year	**133,731**	**$ 2,353**	133,776	$ 2,304

During 2002, the Company issued 10,008,218 common shares at an attributed value of $522 million as part of the consideration to acquire Rio Alto (note 13).

During 2002, the Company issued 60,000 flow-through common shares to a director of the Company at a price of $39.00 per common share, for total proceeds of $2 million. The value of the common shares was determined as the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the allotment.

During 2002, 16,288 common shares were returned to treasury and cancelled on the expiry of the conversion period for exchanging shares of companies previously acquired for common shares of the Company.

Normal Course Issuer Bid

During 2003, the Company purchased 2,734,800 common shares at an average price of $52.51 per common share for a total cost of $144 million. The excess cost over book value of the common shares purchased was applied to reduce retained earnings.

In January 2004, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 6,690,385 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2004 and ending January 23, 2005. As at February 19, 2004, the Company had not purchased any additional shares under the renewed Normal Course Issuer Bid.

Dividend policy

The Company pays regular quarterly dividends in January, April, July and October of each year. On February 19, 2004, the Board of Directors set the Company's regular quarterly dividend at $0.20 per common share (2003 – $0.15 per common share, 2002 – $0.125 per common share, 2001 – $0.10 per common share) commencing with the April 1, 2004 payment.

Stock options

The Company's Option Plan provides for granting of stock options to directors, officers and employees. Stock options granted under the Option Plan have a maximum term of six years to expiry and vest equally over a five-year period starting on the first anniversary date of the grant. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the grant. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price.

Modification of Stock Option Plan

In June 2003, the Company approved a modification to its Option Plan providing the stock option holder the right to elect to receive a cash payment equal to the difference between the exercise price of the stock option and the market price of the Company's common shares on the date of surrender, multiplied by the number of common shares covered by the stock options surrendered, in lieu of receiving common shares.

The modification to the Option Plan was accounted for prospectively and for the year ended December 31, 2003, the Company recorded compensation expense of $200 million. As at December 31, 2003, the total liability for expected cash settlements under the Option Plan is $171 million, of which $130 million is included as a current liability. During the year ended December 31, 2003, cash payments of $31 million were made for 1,337,398 stock options surrendered.

Prior to the modification, the Company disclosed pro-forma measures of net earnings attributable to common shareholders and net earnings attributable to common shareholders per common share as if stock options had been recognized as compensation expense estimated on the date of grant using the Black-Scholes option pricing model. As stock-based compensation is now reflected in the consolidated statement of earnings, the pro-forma disclosures are no longer required.

The following table summarizes information relating to stock options outstanding at December 31, 2003 and 2002:

	2003			2002		
	Stock options (thousands)		**Weighted average exercise price**	Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of year	**12,882**	**$**	**37.13**	12,051	$	34.77
Granted	**668**	**$**	**52.31**	3,845	$	41.88
Exercised for common shares	**(2,690)**	**$**	**33.14**	(2,523)	$	32.54
Surrendered for cash settlement	**(1,337)**	**$**	**34.71**	–	$	–
Forfeited	**(629)**	**$**	**42.78**	(491)	$	40.03
Outstanding – end of year	**8,894**	**$**	**39.44**	12,882	$	37.13
Exercisable – end of year	**2,323**	**$**	**34.65**	3,508	$	32.53

The range of exercise prices of stock options outstanding and exercisable at December 31, 2003 is as follows:

	Stock options outstanding				**Stock options exercisable**		
Range of exercise prices	**Stock options outstanding** (thousands)	**Weighted average remaining term** (years)		**Weighted average exercise price**	**Stock options exercisable** (thousands)		**Weighted average exercise price**
$19.90 to $24.99	**456**	**0.8**	**$**	**22.01**	**427**	**$**	**21.99**
$25.00 to $29.99	**268**	**0.3**	**$**	**27.25**	**236**	**$**	**27.32**
$30.00 to $34.99	**1,561**	**2.0**	**$**	**33.65**	**554**	**$**	**33.66**
$35.00 to $39.99	**3,520**	**3.5**	**$**	**39.04**	**635**	**$**	**39.23**
$40.00 to $44.99	**1,154**	**3.5**	**$**	**42.92**	**271**	**$**	**43.59**
$45.00 to $49.99	**1,431**	**4.3**	**$**	**46.71**	**200**	**$**	**46.48**
$50.00 to $54.66	**504**	**5.7**	**$**	**53.74**	**–**	**$**	**–**
	8,894	**3.2**	**$**	**39.44**	**2,323**	**$**	**34.65**

8. Foreign currency translation adjustment

The foreign currency translation adjustment represents the unrealized gain (loss) on the Company's net investment in self-sustaining foreign operations. Effective July 1, 2002, the Company designated certain US dollar denominated debt as a hedge against its net investment in US dollar-based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment.

		2003		2002
Balance – beginning of year	**$**	**24**	$	73
Unrealized (loss) gain on translation of net investment		**(108)**		(12)
Hedge of net investment with US dollar denominated debt, net of tax		**101**		(37)
Balance – end of year	**$**	**17**	$	24

9. Net earnings attributable to common shareholders per common share

The following table provides a reconciliation between basic and diluted amounts per common share:

(thousands of shares)	**2003**	2002	2001
Weighted average common shares outstanding – basic	**134,235**	127,883	121,300
Effect of dilutive stock options [(1)]	**1,222**	2,744	2,594
Assumed settlement of preferred securities with common shares	**1,954**	2,681	2,883
Weighted average common shares outstanding – diluted	**137,411**	133,308	126,777
Net earnings attributable to common shareholders	**$ 1,407**	$ 570	$ 642
Dividend on preferred securities, net of tax	**5**	6	6
Revaluation of preferred securities, net of tax	**(18)**	(1)	8
Diluted net earnings attributable to common shareholders	**$ 1,394**	$ 575	$ 656
Net earnings attributable to common shareholders per common share			
Basic	**$ 10.48**	$ 4.46	$ 5.30
Diluted	**$ 10.14**	$ 4.31	$ 5.17

(1) The modification of the Option Plan described in note 7 results in a liability and expense for all outstanding stock options. As such, the potential common shares associated with the stock options are not included in diluted earnings per share effective from June 2003, the date of the modification.

For the year ended December 31, 2002, 319,916 stock options with a weighted average exercise price of $48.33 (2001 – 692,790 stock options with a weighted average exercise price of $45.78), were excluded from the calculation as their effect on per common share amounts was anti-dilutive.

10. Financial instruments

Financial contracts

The Company's financial instruments recognized in the consolidated balance sheets consist of cash, accounts receivable, accounts payable, accrued liabilities and long-term debt.

The estimated fair values of financial instruments have been determined based on the Company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The carrying value of cash, accounts receivable, accounts payable, accrued liabilities and long-term debt with variable interest rates approximate their fair value.

The estimated fair values of other financial instruments are as follows:

	2003		2002	
	Carrying value	**Fair value**	Carrying value	Fair value
Asset (liability)				
Derivative financial instruments	**$ –**	**$ 16**	$ –	$ 56
Fixed rate notes	**$ (2,664)**	**$ (2,880)**	$ (3,259)	$ (3,573)

The Company uses certain derivative financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. The following summarizes transactions outstanding as at December 31, 2003:

	Remaining term	Volume	Average price	Index
Oil				
Brent differential swaps	Jan. 2004 – Dec. 2004	40,000 bbl/d	US$1.22	WTI/Dated Brent
Oil price collars	Jan. 2004 – Mar. 2004	123,000 bbl/d	US$25.24 – US$30.87	WTI
	Apr. 2004 – Jun. 2004	120,000 bbl/d	US$25.06 – US$29.84	WTI
	Jul. 2004 – Sep. 2004	120,000 bbl/d	US$25.63 – US$30.41	WTI
	Oct. 2004 – Dec. 2004	60,000 bbl/d	US$25.50 – US$30.32	WTI
Natural gas				
AECO collars	Jan. 2004 – Mar. 2004	300,000 GJ/d	C$6.00 – C$10.14	AECO

	Remaining term	Amount ($ millions)	Average exchange rate (US$/C$)
Foreign currency			
Currency collars			
	Jan. 2004 – Aug. 2004	US$20/month	1.51 – 1.59
	Jan. 2004 – Sep. 2004	US$5/month	1.52 – 1.59
	Jan. 2004 – Dec. 2004	US$3/month	1.45 – 1.54
	Jan. 2004 – Aug. 2005	US$10/month	1.37 – 1.49

	Remaining term	Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Currency swap	Jan. 2004 – Dec. 2005	US$125	1.55	7.69%	7.30%

	Remaining term	Amount ($ millions)	Fixed rate	Floating rate
Interest rate				
Swaps – fixed to floating	Jan. 2004 – Jul. 2004	US$200	6.70%	LIBOR + 2.09%
	Jan. 2004 – Jul. 2006	US$200	6.70%	LIBOR + 1.58%
	Jan. 2004 – Jan. 2005	US$200	7.20%	LIBOR + 3.00%
	Jan. 2004 – Jan. 2007	US$200	7.20%	LIBOR + 2.23%
	Jan. 2004 – Oct. 2012	US$350	5.45%	LIBOR + 0.81%
Swaps – floating to fixed	Jan. 2004 – Mar. 2007	C$16	7.36%	CDOR

Credit risk

Accounts receivable are mainly with customers in the oil and natural gas industry and are subject to normal industry credit risks. The Company minimizes this risk by entering into sales contracts with only highly rated entities. In addition, the Company reviews its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. The Company is also exposed to certain losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company minimizes this credit risk by entering into agreements with only highly rated financial institutions.

11. Commitments

The Company has committed to certain payments as follows:

	2004	2005	2006	2007	2008	Thereafter
Natural gas transportation	$ 180	$ 169	$ 143	$ 103	$ 77	$ 194
Oil transportation and pipeline	$ 15	$ 13	$ 13	$ 15	$ 13	$ 167
Offshore equipment operating lease	$ 169	$ 129	$ 75	$ 75	$ 75	$ 367
Electricity	$ 28	$ 27	$ 27	$ –	$ –	$ –
Office lease	$ 20	$ 20	$ 19	$ 17	$ 16	$ 50
Processing	$ 6	$ 5	$ 2	$ –	$ –	$ –

12. Supplemental disclosure of cash flow information

Changes in non-cash working capital were as follows:

		2003		2002		2001
Decrease (increase) in non-cash working capital						
Accounts receivable and other	**$**	**35**	$	(164)	$	80
Accounts payable		**125**		(145)		(60)
Accrued liabilities		**122**		154		(107)
Net change in non-cash working capital	**$**	**282**	$	(155)	$	(87)
Relating to:						
Operating activities	**$**	**(48)**	$	(157)	$	(42)
Financing activities		**(11)**		27		7
Investing activities		**341**		(25)		(52)
	$	**282**	$	(155)	$	(87)

Other cash flow information:

		2003		2002		2001
Interest paid	**$**	**178**	$	132	$	127
Taxes paid	**$**	**51**	$	160	$	161

13. Business combination

Rio Alto Exploration Ltd.

In July 2002, the Company paid cash of $850 million and issued 10,008,218 common shares with an attributed value of $522 million to acquire all of the issued and outstanding common shares of Rio Alto Exploration Ltd. ("Rio Alto") by way of a plan of arrangement (the "Plan of Arrangement"). Rio Alto was engaged in the exploration for and production of oil and natural gas in western Canada and, through wholly owned subsidiaries, in South America. Under the Plan of Arrangement, the subsidiaries of Rio Alto that held its South American properties were sold to a new company, Rio Alto Resources International Inc. ("Rio Alto International"), and each shareholder of Rio Alto received one common share of Rio Alto International for each Rio Alto common share held.

The acquisition was accounted for based on the purchase method. Results of Rio Alto are consolidated with the results of the Company since the date of acquisition. The allocation of the purchase price to assets acquired and liabilities assumed based on their fair values is set out in the following table:

		July 1, 2002
Purchase price:		
Cash consideration	$	850
Share consideration		522
Cash acquired		(7)
Non-cash working capital deficit assumed		92
Long-term debt assumed		936
Total purchase price	$	2,393
Purchase price allocated as follows:		
Property, plant and equipment	$	3,412
Future site restoration		(44)
Future income tax		(975)
	$	2,393

14. Segmented information

The Company's oil and natural gas activities are conducted in three geographic segments: North America, the North Sea and Offshore West Africa. These activities relate to the exploration, development, production and marketing of oil, natural gas liquids and natural gas.

The Company's Horizon Project has been classified as a separate segment. As the bitumen will be recovered through mining operations, this project constitutes a distinct segment from oil and natural gas activities. There are currently no revenues for this project and all directly related expenditures have been capitalized.

Midstream activities include the Company's pipeline operations and an electricity co-generation system.

	Oil and natural gas					
	North America			North Sea		
	2003	2002	2001	**2003**	2002	2001
Revenue	**$ 4,829**	$ 3,610	$ 3,163	**$ 961**	$ 612	$ 534
Less: royalties	**(867)**	(564)	(551)	**1**	(33)	(28)
	3,962	3,046	2,612	**962**	579	506
Expenses						
Production	**845**	656	597	**314**	229	123
Transportation	**263**	273	166	**30**	20	11
Depletion, depreciation and amortization	**1,248**	1,033	746	**268**	193	129
Administration	**87**	61	37	**–**	–	1
Stock-based compensation	**190**	–	–	**7**	–	–
Interest	**153**	156	130	**4**	3	8
Foreign exchange (gain) loss	**(345)**	(52)	60	**39**	21	2
Loss on sale of United States assets	**–**	–	24	**–**	–	–
	2,441	2,127	1,760	**662**	466	274
Earnings before taxes	**1,521**	919	852	**300**	113	232
Taxes other than income tax	**10**	11	9	**97**	51	59
Current income tax	**59**	21	15	**23**	(19)	62
Future income tax	**246**	322	290	**59**	82	(9)
Net earnings	**1,206**	565	538	**121**	(1)	120
Dividend on preferred securities, net of tax	**(5)**	(6)	(6)	**–**	–	–
Revaluation of preferred securities, net of tax	**18**	1	(8)	**–**	–	–
Net earnings attributable to common shareholders	**$ 1,219**	$ 560	$ 524	**$ 121**	$ (1)	$ 120

(1) Eliminates internal transportation and electricity charges.

Capital expenditures

	2003				
	Cash consideration	**Non-cash consideration**	**Capital expenditures**	**Fair value adjustments** (1)	**Capitalized costs**
Oil and natural gas					
North America – business combination	**$ –**	**$ –**	**$ –**	**$ –**	**$ –**
North America – oil and natural gas	**1,769**	**–**	**1,769**	**–**	**1,769**
North Sea	**338**	**–**	**338**	**25**	**363**
Offshore West Africa	**176**	**–**	**176**	**–**	**176**
	2,283	**–**	**2,283**	**25**	**2,308**
Horizon Project	**152**	**–**	**152**	**–**	**152**
Midstream	**11**	**–**	**11**	**–**	**11**
Abandonments (2)	**40**	**–**	**40**	**–**	**40**
Head office	**20**	**–**	**20**	**–**	**20**
	$ 2,506	**$ –**	**$ 2,506**	**$ 25**	**$ 2,531**

(1) Future income tax adjustments on non tax base assets and other fair value adjustments.
(2) Abandonment expenditures were incurred in the following segments; $30 million North America, $1 million North Sea and $9 million Offshore West Africa (2002 – $ 32 million North America, $9 million North Sea and $2 million Offshore West Africa).

Offshore West Africa			Midstream			Intersegment eliminations (1)			Total		
2003	2002	2001	2003	2002	2001	**2003**	2002	2001	**2003**	2002	2001
$ 156	$ 102	$ 42	**$ 61**	$ 52	$ 27	**$ (35)**	$ (34)	$ (9)	**$ 5,972**	$ 4,342	$ 3,757
(6)	(3)	(1)	**–**	–	–	**–**	–	–	**(872)**	(600)	(580)
150	99	41	**61**	52	27	**(35)**	(34)	(9)	**5,100**	3,742	3,177
38	35	27	**15**	14	11	**(3)**	(3)	(2)	**1,209**	931	756
1	–	–	**–**	–	–	**(32)**	(31)	(7)	**262**	262	170
42	80	24	**7**	8	4	**–**	–	–	**1,565**	1,314	903
–	–	–	**–**	–	–	**–**	–	–	**87**	61	38
3	–	–	**–**	–	–	**–**	–	–	**200**	–	–
–	–	–	**–**	–	–	**–**	–	–	**157**	159	138
(6)	–	1	**–**	–	–	**–**	–	–	**(312)**	(31)	63
–	–	–	**–**	–	–	**–**	–	–	**–**	–	24
78	115	52	**22**	22	15	**(35)**	(34)	(9)	**3,168**	2,696	2,092
72	(16)	(11)	**39**	30	12	**–**	–	–	**1,932**	1,046	1,085
–	1	1	**–**	–	–	**–**	–	–	**107**	63	69
10	6	–	**–**	–	–	**–**	–	–	**92**	8	77
18	(17)	(3)	**16**	13	5	**–**	–	–	**339**	400	283
44	(6)	(9)	**23**	17	7	**–**	–	–	**1,394**	575	656
	–	–	**–**	–	–	**–**	–		**(5)**	(6)	(6)
–	–	–	**–**	–	–	**–**	–	–	**18**	1	(8)
$ 44	$ (6)	$ (9)	**$ 23**	$ 17	$ 7	**$ –**	$ –	$ –	**$ 1,407**	$ 570	$ 642

	2002 Cash consideration	Non-cash consideration	Capital expenditures	Fair value adjustments (1)	Capitalized costs
Oil and natural gas					
North America – business combination	$ 844	$ 1,550	$ 2,394	$ 1,019	$ 3,413
North America – oil and natural gas	1,026	–	1,026	–	1,026
North Sea	323	–	323	232	555
Offshore West Africa	186	–	186	–	186
	2,379	1,550	3,929	1,251	5,180
Horizon Project	68	–	68	–	68
Midstream	20	–	20	–	20
Abandonments (2)	43	–	43	–	43
Head office	10	–	10	–	10
	$ 2,520	$ 1,550	$ 4,070	$ 1,251	$ 5,321

Segmented property, plant and equipment, net	2003	2002
Oil and natural gas		
North America	$ 10,841	$ 10,252
North Sea	1,157	1,277
Offshore West Africa	651	518
Horizon Project	381	229
Midstream	200	196
Head office	39	28
	$ 13,269	$ 12,500

Segmented assets	2003	2002
Oil and natural gas		
North America	$ 11,582	$ 10,917
North Sea	1,282	1,427
Offshore West Africa	687	549
Horizon Project	381	229
Midstream	227	209
Head office	39	28
	$ 14,198	$ 13,359

15. Subsequent event

Acquisition of Petrovera Partnership

On February 18, 2004, the Company acquired certain resource properties located in East Central Alberta and Saskatchewan (collectively known as the Petrovera Partnership) for aggregate consideration of $701 million. In a separate transaction, the Company sold specific resource properties in the Petrovera Partnership, representing approximately one third of the total acquisition, to another independent producer for proceeds of $234 million, resulting in a net cost of $467 million for the retained properties. The net production from the working interests retained by the Company is approximately 27,500 barrels per day of heavy oil and nine million cubic feet per day of natural gas together with volumes associated with royalty interests of 1,200 barrels per day of heavy oil and two million cubic feet per day of natural gas.

16. Differences between Canadian and United States generally accepted accounting principles

The Company's consolidated financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"). These principles conform in all material respects with those in the United States ("US GAAP") except for those noted below. Differences arising from US GAAP disclosure requirements are not addressed.

The application of US GAAP would have the following effects on consolidated net earnings as reported:

(millions of Canadian dollars, except per common share amounts)	Notes	2003	2002	2001
Net earnings – Canadian GAAP		$ 1,394	$ 575	$ 656
Adjustments, net of tax				
Depletion	(A,D)	37	5	5
Derivative financial instruments	(B)	(49)	29	61
Dividend on preferred securities	(C)	(5)	(6)	(6)
Revaluation of preferred securities	(C)	18	1	(8)
Accretion of asset retirement obligation	(D)	(37)	–	–
Cumulative effect of change in accounting policy	(D)	(4)	–	–
Tax effect of flow-through shares	(E)	–	(1)	–
Net earnings – US GAAP		$ 1,354	$ 603	$ 708
Net earnings – US GAAP per common share				
Basic		$ 10.09	$ 4.72	$ 5.84
Diluted		$ 9.76	$ 4.56	$ 5.70

Comprehensive income under US GAAP would be as follows:

(millions of Canadian dollars)	Notes	2003	2002	2001
Net earnings – US GAAP		**$ 1,354**	$ 603	$ 708
Adoption of FAS 133	(B)	**–**	–	(124)
Amortization of FAS 133 adjustment	(B)	**20**	31	54
Foreign currency translation adjustment	(F)	**(7)**	(49)	73
Comprehensive income		**$ 1,367**	$ 585	$ 711

The application of US GAAP would have the following effects on the consolidated balance sheets as reported:

		2003		
(millions of Canadian dollars)	Notes	**Canadian GAAP**	**Increase (Decrease)**	**US GAAP**
Property, plant and equipment	(A,D)	**$ 13,269**	**$ 385**	**$ 13,654**
Derivative financial instruments asset (liability)	(B)	**$ –**	**$ 16**	**$ 16**
Long-term debt	(C)	**$ 2,645**	**$ 103**	**$ 2,748**
Asset retirement obligation	(D)	**$ 447**	**$ 450**	**$ 897**
Future income tax	(A,B,D)	**$ 3,588**	**$ –**	**$ 3,588**
Shareholders' equity		**$ 6,117**	**$ (152)**	**$ 5,965**

		2002		
(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (Decrease)	US GAAP
Property, plant and equipment	(A)	$ 12,500	$ (68)	$ 12,432
Derivative financial instruments asset (liability)	(B)	$ –	$ 56	$ 56
Long-term debt	(C)	$ 4,074	$ 126	$ 4,200
Future income tax	(A,B)	$ 3,188	$ 4	$ 3,192
Shareholders' equity		$ 4,868	$ (142)	$ 4,726

Notes:

(A) Using Canadian full cost accounting rules, costs capitalized in each cost centre, net of future income taxes and future site restoration costs, are limited to an amount equal to the undiscounted, unescalated future net revenues from proved reserves plus the lower of cost or estimated fair market value of unproved properties (the "ceiling test"). Under the full cost method of accounting as set forth by the US Securities and Exchange Commission, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are discounted at 10% and estimated future financing and administrative expenses are not deducted from net revenues.

(B) The Company uses certain derivative financial instruments to manage its commodity prices and foreign currency exposure in relation to future firmly committed and anticipated sales transactions. The Company has also used interest rate swaps to manage its interest rate exposure. Under Canadian GAAP, these derivative financial instruments are accounted for as hedges.

Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards ("FAS") 133 "Accounting for Derivative Instruments and Hedging Activities" and FAS 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities" to account for its commodity prices and interest rate swap derivative financial instruments under US GAAP. Under FAS 133, all derivative financial instruments are recognized in the consolidated balance sheets at their fair value. Changes in the fair value of derivative financial instruments are recognized in consolidated net earnings unless specific criteria for hedging are met. In 2003, 2002 and 2001, no derivative financial instruments were designated as hedges for US GAAP purposes.

In 2001, the adoption of FAS 133 resulted in the Company recognizing a derivative financial instruments liability of $183 million and a charge to comprehensive income of $124 million, net of future income tax recoveries of $59 million. Of the initial liability recognized on January 1, 2001, a loss of $54 million, net of future income tax recoveries of $26 million, was reclassified to net earnings during 2001. For 2002, a loss of $31 million, net of future income tax recoveries of $15 million, was amortized to net earnings. For 2003, a loss of $20 million, net of future income tax recoveries of $9 million, was amortized to net earnings.

Under US GAAP, foreign currency swap contracts used to hedge foreign currency exposure to anticipated, but not firmly committed, transactions cannot be accounted for as hedges. Accordingly, for US GAAP reporting, gains and losses from changes in the fair market value of foreign currency swap contracts related to these anticipated transactions are recognized in net earnings when those changes in market value occur.

(C) Under Canadian GAAP, the preferred securities are considered to be equity because the Company has the unrestricted right to pay dividends, principal and principal prepayments with common shares. Under US GAAP, the Company's preferred securities would be classified as debt rather than as equity. Accordingly, the dividend on the preferred securities would be classified as an expense rather than a dividend and the revaluation of preferred securities would be included in foreign exchange (gain) loss in determining consolidated net earnings.

(D) Effective January 1, 2003, the Company adopted FAS 143 "Accounting for Asset Retirement Obligations" for US GAAP reporting purposes. Under FAS 143, all statutory, contractual, and legal obligations relating to asset retirements are recognized in the consolidated balance sheets at their fair value. The liability is adjusted for accretion of discount and any changes in the amount or timing of the underlying cash flows. The standard requires the cumulative effect on prior years to be included in net earnings.

Adoption of FAS 143 had the following effects on the Company's consolidated financial statements:

(millions of Canadian dollars)		**December 31, 2003**
Consolidated balance sheet		
Increase property, plant and equipment	**$**	**445**
Increase asset retirement obligation	**$**	**450**
Increase future income tax liability	**$**	**3**
Consolidated statement of earnings, net of tax		
Decrease depletion, depreciation and amortization	**$**	**(33)**
Increase accretion of asset retirement obligation	**$**	**37**
Increase cumulative effect of change in accounting policy	**$**	**4**

The Company's pipelines and co-generation plant have indeterminant lives and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligation for these assets will be recorded in the year in which the lives of the assets are determinable.

(E) Under Canadian GAAP, the future income tax effect of flow-through shares is deducted from share capital. However, under US GAAP, the future income tax effect of flow-through shares is expensed immediately.

(F) Under US GAAP, exchange gains and losses arising from the translation of self-sustaining foreign operations are included in comprehensive income.

(G) Recently Issued Accounting Standards

FULL COST ACCOUNTING IN THE OIL AND GAS INDUSTRY

In September 2003, the CICA issued Accounting Guideline 16 "Oil and Gas Accounting – Full Cost". The Guideline modifies the ceiling test, which limits the aggregate capitalized costs that may be carried forward to future periods. Specific new guidance was provided on several issues, including the frequency of conducting cost centre impairment tests, the testing for cost centre recoverability and the method of determining fair value. The Guideline recommends that cost centre impairment tests should be conducted at each annual balance sheet date. Recovery of costs is tested by comparing the carrying amount of the oil and natural gas assets to the undiscounted cash flows from those assets using proved reserves and expected future prices and costs. If the carrying amount exceeds the recoverable amount, then impairment should be recognized on the amount by which the carrying amount of the assets exceeds the present value of expected cash flows using proved and probable reserves and expected future prices and costs. The effective date of the Guideline is for fiscal years beginning on or after January 1, 2004, with early adoption recommended. This guideline will apply to the ceiling test relating to the impairment of the Company's property, plant and equipment. Adoption of this standard would not have had an impact on the Company's financial statements for the year ended December 31, 2003.

ASSET RETIREMENT OBLIGATIONS

In January 2003, the CICA issued Section 3110 "Asset Retirement Obligations". The Section requires the recognition of the fair value of the retirement obligation for related long-term assets as a liability. Retirement costs equal to the retirement obligation are capitalized as part of the cost of the associated capital asset and amortized to expense through depletion over the life of the asset. In subsequent periods, the liability is adjusted for the passage of time and any changes in the amount or timing of the underlying future cash flows. This standard will be adopted retroactively effective January 1, 2004, and prior period comparative balances will be restated. Adoption of the standard will have the following effects on the Company's financial statements:

(millions of Canadian dollars)		January 1, 2004
Consolidated balance sheet		
Increase property, plant and equipment	$	445
Increase asset retirement obligation	$	450
Increase future income tax liability	$	3
Decrease foreign currency translation adjustment	$	(14)
Increase retained earnings	$	6

The Company's pipelines and co-generation plant have indeterminant lives and therefore the fair values of the related asset retirement obligations canno be reasonably determined. The asset retirement obligation for these assets will be recorded in the year in which the lives of the assets are determin able.

LIABILITIES AND EQUITY

In January 2004, the CICA issued amendments to Section 3860 "Financial Instruments". The amended Section requires the recognition of certai financial instruments that may be settled in cash or by an issuer's own equity instruments, at the issuer's discretion, as liabilities. This amended Sectio is effective for periods ending after November 1, 2004, and will require the Company to reclassify its preferred securities from shareholders' equit to long-term debt. Dividends on the preferred securities would be reclassified to interest expense.

ACCOUNTING FOR THE IMPAIRMENT OF LONG-LIVED ASSETS

In January 2003, the CICA issued Section 3063 "Impairment of Long-lived Assets" effective for fiscal years beginning on or after April 1, 2003. The Sectio indicates that impairment losses occur when the carrying value of the asset exceeds the sum of the undiscounted cash flows expected from its use and measured as the amount by which the carrying amount exceeds its fair value. This Section will apply to the Company's midstream operating segment only

HEDGING RELATIONSHIPS

In December 2001, the CICA issued Accounting Guideline 13, "Hedging Relationships". The effective date of this Guideline was deferred to fisca years beginning on or after July 1, 2003. The Guideline addresses the types of items that qualify for hedge accounting, the formal documentatio required to enable the use of hedge accounting and the requirement to evaluate hedges for effectiveness. The Guideline does not specify how hedg accounting should be applied but does require financial instruments that are not designated as hedges be recorded at fair value on the Company' consolidated balance sheet, with changes in fair value recorded in earnings. This Guideline will be adapted prospectively effective January 1, 200 and will have the following effects on the Company's financial statements:

(millions of Canadian dollars)		January 1, 200
Consolidated balance sheet		
Increase derivative financial instruments asset	$	16
Increase future income tax liability	$	7
Increase deferred revenue	$	9

VARIABLE INTEREST ENTITIES

In June 2003, the CICA issued Accounting Guideline 15, "Consolidation of Variable Interest Entities" (VIEs) with the purpose of harmonizing Canadia Standards with FASB Interpretation No. 46 "Consolidation of Variable Interest Entities". The Guideline requires enterprises to identify VIEs in whic they have an interest, determine if they are the primary beneficiary of such entities and if so, consolidate them. A transitional provision to disclos VIEs prior to the effective date of the Guideline was to be effective January 1, 2004; however, the CICA has suspended this provision pending revie of recent changes to Interpretation No. 46, which are described in Interpretation 46R. The prospective treatment of the consolidation requirement o the Guideline remains effective for all annual and interim periods beginning on or after November 1, 2004.

Supplementary oil & gas information (unaudited)

This supplementary oil and natural gas information is provided in accordance with the United States FAS 69, "Disclosures about Oil and Gas Producing Activities", and where applicable is reconciled to the US GAAP financial information.

Net proved oil and natural gas reserves

The Company retains independent petroleum engineering consultants to evaluate the majority of the Company's proved oil and natural gas reserves, with the remainder evaluated by the Company's internal petroleum engineers.

- For the year ended December 31, 2003, the reports by Sproule Associates Limited ("Sproule") covered 100% of the Company's reserves;
- For the year ended December 31, 2002, the reports by Sproule covered 89% of the Company's reserves; and
- For the year ended December 31, 2001, the reports by Sproule covered 91% of the Company's reserves.

Proved oil and natural gas reserves are the estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Estimates of oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following table summarizes the Company's proved and proved developed oil and natural gas reserves, net of royalties, as at December 31, 2003, 2002 and 2001:

Oil and natural gas liquids (mmbbl)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Net proved reserves				
Reserves, December 31, 2000	568	93	30	691
Extensions and discoveries	13	–	37	50
Purchases of reserves in place	14	–	8	22
Sales of reserves in place	(1)	–	–	(1)
Production	(54)	(13)	(1)	(68)
Revisions of previous estimates	43	(2)	(14)	27
Reserves, December 31, 2001	583	78	60	721
Extensions and discoveries	26	1	14	41
Purchases of reserves in place	44	114	–	158
Sales of reserves in place	(1)	(18)	–	(19)
Production	(55)	(13)	(2)	(70)
Revisions of previous estimates	(26)	40	3	17
Reserves, December 31, 2002	571	202	75	848
Extensions and discoveries	**55**	**–**	**13**	**68**
Improved recovery	**9**	**–**	**–**	**9**
Purchases of reserves in place	**7**	**27**	**–**	**34**
Sales of reserves in place	**–**	**–**	**–**	**–**
Production	**(56)**	**(21)**	**(4)**	**(81)**
Revisions of previous estimates	**2**	**14**	**1**	**17**
Reserves, December 31, 2003	**588**	**222**	**85**	**895**
Net proved developed reserves:				
December 31, 2000	328	61	2	391
December 31, 2001	344	51	20	415
December 31, 2002	340	107	27	474
December 31, 2003	**348**	**138**	**23**	**509**

Natural gas (bcf)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Net proved reserves				
Reserves, December 31, 2000	1,895	91	53	2,039
Extensions and discoveries	379	–	–	379
Purchases of reserves in place	134	–	23	157
Sales of reserves in place	(20)	–	–	(20)
Production	(255)	(4)	–	(259)
Revisions of previous estimates	(69)	7	(9)	(71)
Reserves, December 31, 2001	2,064	94	67	2,225
Extensions and discoveries	106	–	4	110
Purchases of reserves in place	699	18	–	717
Sales of reserves in place	(3)	(56)	–	(59)
Production	(346)	(10)	(1)	(357)
Revision of previous estimates	(74)	25	1	(48)
Reserves, December 31, 2002	2,446	71	71	2,588
Extensions and discoveries	**301**	**–**	**6**	**307**
Improved recovery	**8**	**–**	**–**	**8**
Purchases of reserves in place	**50**	**19**	**–**	**69**
Sales of reserves in place	**(3)**	**–**	**–**	**(3)**
Production	**(355)**	**(17)**	**(3)**	**(375)**
Revision of previous estimates	**(21)**	**(11)**	**(10)**	**(42)**
Reserves, December 31, 2003	**2,426**	**62**	**64**	**2,552**
Net proved developed reserves:				
December 31, 2000	1,569	32	–	1,601
December 31, 2001	1,845	19	16	1,880
December 31, 2002	2,185	57	27	2,269
December 31, 2003	**2,140**	**46**	**12**	**2,198**

Capitalized costs related to oil and natural gas activities

			2003	
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Proved properties	**$ 15,125**	**$ 1,917**	**$ 568**	**$ 17,610**
Unproved properties	**789**	**56**	**237**	**1,082**
	15,914	**1,973**	**805**	**18,692**
Less: accumulated depletion and depreciation	**(4,984)**	**(534)**	**(140)**	**(5,658)**
Net capitalized costs	**$ 10,930**	**$ 1,439**	**$ 665**	**$ 13,034**

			2002	
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Proved properties	$ 13,197	$ 1,559	$ 480	$ 15,236
Unproved properties	667	62	132	861
	13,864	1,621	612	16,097
Less: accumulated depletion and depreciation	(3,679)	(344)	(94)	(4,117)
Net capitalized costs	$ 10,185	$ 1,277	$ 518	$ 11,980

			2001	
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Proved properties	$ 9,001	$ 991	$ 377	$ 10,369
Unproved properties	424	60	48	532
	9,425	1,051	425	10,901
Less: accumulated depletion and depreciation	(2,694)	(185)	(15)	(2,894)
Net capitalized costs	$ 6,731	$ 866	$ 410	$ 8,007

Costs incurred in oil and natural gas activities

(millions of Canadian dollars)	2003 North America	North Sea	Offshore West Africa	Total
Property acquisitions				
Proved	$ 236	$ 100	$ –	$ 336
Unproved	116	23	–	139
Exploration	190	47	28	265
Development	1,227	193	148	1,568
Finding and development costs	1,769	363	176	2,308
Asset retirement costs	80	59	9	148
Actual retirement expenditures	(30)	(1)	(9)	(40)
Costs incurred	$ 1,819	$ 421	$ 176	$ 2,416

(millions of Canadian dollars)	2002 North America	North Sea	Offshore West Africa	Total
Property acquisitions				
Proved	$ 3,367	$ 373	$ –	$ 3,740
Unproved	369	28	30	427
Exploration	96	10	81	187
Development	607	145	74	826
Costs incurred	$ 4,439	$ 556	$ 185	$ 5,180

(millions of Canadian dollars)	2001 North America	North Sea	Offshore West Africa	Total
Property acquisitions				
Proved	$ 647	$ –	$ 62	$ 709
Unproved	73	4	–	77
Exploration	61	25	64	150
Development	848	68	78	994
Costs incurred	$ 1,629	$ 97	$ 204	$ 1,930

Results of operations from oil and natural gas producing activities

The Company's results of operations from oil and natural gas producing activities for the years ended December 31, 2003, 2002 and 2001 are summarized in the following tables:

(millions of Canadian dollars)	2003 North America	North Sea	Offshore West Africa	Total
Oil and natural gas revenue, net of royalties	$ 3,961	$ 962	$ 150	$ 5,073
Production	(845)	(314)	(38)	(1,197)
Transportation	(263)	(30)	(1)	(294)
Depletion, depreciation and amortization	(1,203)	(250)	(42)	(1,495)
Accretion of asset retirement obligation	(23)	(39)	(1)	(63)
Petroleum revenue tax	–	(97)	–	(97)
Income tax	(673)	(93)	(24)	(790)
Results of operations	$ 954	$ 139	$ 44	$ 1,137

(millions of Canadian dollars)	2002 North America	North Sea	Offshore West Africa	Total
Oil and natural gas revenue, net of royalties	$ 3,045	$ 579	$ 99	$ 3,723
Production	(656)	(229)	(35)	(920)
Transportation	(273)	(20)	–	(293)
Depletion, depreciation and amortization	(1,024)	(193)	(80)	(1,297)
Petroleum revenue tax	–	(51)	–	(51)
Income tax	(431)	(34)	11	(454)
Results of operations	$ 661	$ 52	$ (5)	$ 708

(millions of Canadian dollars)	2001 North America	North Sea	Offshore West Africa	Total
Oil and natural gas revenue, net of royalties	$ 2,610	$ 506	$ 41	$ 3,157
Production	(597)	(123)	(27)	(747)
Transportation	(166)	(11)	–	(177)
Depletion, depreciation and amortization	(737)	(129)	(24)	(890)
Loss on sale of US assets	(24)	–	–	(24)
Petroleum revenue tax	–	(59)	–	(59)
Income tax	(447)	(55)	3	(499)
Results of operations	$ 639	$ 129	$ (7)	$ 761

Standardized measure of discounted future net cash flows from proved oil and natural gas reserves and changes therein

The following standardized measure of discounted future net cash flows from proved oil and natural gas reserves has been computed using year-end sales prices and costs and year-end statutory income tax rates. A discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows. The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows due to several factors including:

- Future production will include production not only from proved properties, but may also include production from probable and potential reserves;
- Future production of oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future rather than year-end sales prices and costs will apply;
- Economic factors such as interest rates, income tax rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration expenditures; and
- Future development and site restoration costs will differ from those estimated.

Future net revenues, development, production and restoration costs have been based upon the estimates referred to above.

The following tables summarize the Company's future net cash flows relating to proved oil and natural gas reserves based on the standardized measure as prescribed in FAS 69:

	2003			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Future cash inflows	**$ 32,720**	**$ 9,099**	**$ 3,192**	**$ 45,011**
Future production costs	**(9,480)**	**(3,015)**	**(1,179)**	**(13,674)**
Future development and site restoration costs	**(2,393)**	**(1,749)**	**(697)**	**(4,839)**
Future income taxes	**(7,295)**	**(2,801)**	**–**	**(10,096)**
Future net cash flows	**13,552**	**1,534**	**1,316**	**16,402**
10% annual discount for timing of future cash flows	**(6,203)**	**(336)**	**(432)**	**(6,971)**
Standardized measure of future net cash flows	**$ 7,349**	**$ 1,198**	**$ 884**	**$ 9,431**

	2002			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 34,980	$ 9,682	$ 3,206	$ 47,868
Future production costs	(7,238)	(3,250)	(911)	(11,399)
Future development and site restoration costs	(1,770)	(1,691)	(616)	(4,077)
Future income taxes	(8,046)	(2,991)	–	(11,037)
Future net cash flows	17,926	1,750	1,679	21,355
10% annual discount for timing of future cash flows	(7,361)	(434)	(556)	(8,351)
Standardized measure of future net cash flows	$ 10,565	$ 1,316	$ 1,123	$ 13,004

	2001			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 18,565	$ 3,089	$ 1,587	$ 23,241
Future production costs	(6,587)	(1,368)	(576)	(8,531)
Future development and site restoration costs	(1,204)	(354)	(556)	(2,114)
Future income taxes	(2,576)	(549)	–	(3,125)
Future net cash flows	8,198	818	455	9,471
10% annual discount for timing of future cash flows	(3,136)	(241)	(133)	(3,510)
Standardized measure of future net cash flows	$ 5,062	$ 577	$ 322	$ 5,961

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

(millions of Canadian dollars)	**2003**	2002	2001
Sales of oil and natural gas produced, net of production costs	**$ (3,582)**	$ (2,510)	$ (2,232)
Net changes in sales prices and production costs	**(2,750)**	8,453	(9,685)
Extensions, discoveries and improved recovery	**1,360**	972	1,027
Changes in estimated future development costs	**(346)**	(1,284)	(174)
Purchases of proved reserves in place	**594**	4,973	413
Sales of proved reserves in place	**(8)**	(494)	(34)
Revisions of previous reserve estimates	**144**	360	56
Accretion of discount	**2,000**	794	1,745
Changes in production timing and other	**(1,411)**	502	(726)
Net change in income taxes	**426**	(4,723)	3,692
Net change	**(3,573)**	7,043	(5,918)
Balance – beginning of year	**13,004**	5,961	11,879
Balance – end of year	**$ 9,431**	$ 13,004	$ 5,961

Ten-year review

Years ended December 31	**2003**	2002	2001	2000	1999	1998	1997	1996	1995	1994
FINANCIAL INFORMATION										
(millions of Canadian dollars, except per share amounts)										
Cash flow from operations attributable to common shareholders	**3,160**	2,254	1,920	1,884	724	444	503	360	154	153
Per share – basic	**$ 23.54**	$ 17.63	$ 15.83	$ 16.14	$ 6.96	$ 4.47	$ 5.13	$ 4.32	$ 2.22	$ 2.39
Net earnings attributable to common shareholders	**1,407**	570	642	767	220	39	111	95	42	54
Per share – basic	**$ 10.48**	$ 4.46	$ 5.30	$ 6.57	$ 2.11	$ 0.40	$ 1.14	$ 1.14	$ 0.61	$ 0.85
Capital expenditures, net of dispositions (including business combinations)	**2,506**	4,070	1,885	2,823	1,901	610	1,119	1,204	239	331
Balance sheet information										
Working capital (deficiency) surplus	**(505)**	(14)	(6)	(77)	36	58	(19)	(1)	10	4
Property, plant and equipment, net	**13,269**	12,500	8,443	7,142	4,554	3,034	2,746	1,912	836	678
Total assets	**14,198**	13,359	8,967	7,754	4,851	3,228	2,931	2,063	900	738
Long-term debt	**2,645**	4,074	2,669	2,455	2,157	1,426	1,136	588	238	243
Shareholders' equity	**6,117**	4,868	3,806	3,203	1,892	1,258	1,204	1,074	496	356
SHARE INFORMATION										
Common shares outstanding (thousands)	**133,731**	133,776	121,201	122,279	111,454	99,809	98,819	97,383	74,074	66,709
Weighted average shares outstanding (thousands)	**134,235**	127,883	121,300	116,701	103,906	99,331	98,042	83,246	69,319	63,873
Dividend per common share	**$ 0.60**	$ 0.50	$ 0.40	$ –	$ –	$ –	$ –	$ –	$ –	$ –
Trading statistics										
TSX										
Trading volume (thousands)	**147,675**	154,829	133,744	141,853	107,615	102,610	100,538	99,222	60,935	35,291
Share price (C$/share)										
High	**$ 67.22**	$ 54.54	$ 52.35	$ 56.20	$ 38.60	$ 31.50	$ 44.25	$ 39.40	$ 20.25	$ 22.75
Low	**$ 45.20**	$ 37.60	$ 35.90	$ 29.80	$ 19.80	$ 18.25	$ 28.90	$ 19.25	$ 10.75	$ 13.38
Close	**$ 65.37**	$ 46.80	$ 38.31	$ 41.50	$ 35.25	$ 23.00	$ 30.60	$ 37.60	$ 20.00	$ 13.75
NYSE										
Trading volume (thousands)	**11,729**	7,966	5,191	793	–	–	–	–	–	–
Share price (US$/share)										
High	**$ 51.39**	$ 34.88	$ 34.51	$ 37.81	$ –	$ –	$ –	$ –	$ –	$ –
Low	**$ 29.25**	$ 23.55	$ 22.80	$ 24.75	$ –	$ –	$ –	$ –	$ –	$ –
Close	**$ 50.44**	$ 29.67	$ 24.40	$ 27.50	$ –	$ –	$ –	$ –	$ –	$ –
RATIOS										
Debt to cash flow	**0.9x**	1.8x	1.4x	1.3x	3.0x	3.2x	2.3x	1.6x	1.5x	1.6x
Debt to book capitalization	**31.6%**	45.6%	41.4%	43.5%	53.3%	53.1%	48.5%	35.4%	32.4%	40.5%
Return on average common shareholders' equity, after tax	**25.7%**	13.8%	18.8%	31.6%	14.5%	3.2%	9.8%	13.0%	10.3%	19.1%
Daily production per thousand common shares (boe/d)	**3.4**	3.3	3.0	2.5	2.6	1.9	1.8	1.5	1.0	0.8
Reserves per common share (boe)	**13.6**	13.4	12.2	11.5	9.6	7.5	7.1	5.3	3.6	3.5
Net asset value per common share (1)	**$ 97.93**	$ 78.55	$ 70.02	$ 87.43	$ 48.61	$ 31.74	$ 27.40	$ 25.84	$ 18.40	$ 15.11

(1) Based upon 10% discounted, escalated price pre-tax proved and probable net asset values as reported in the Company's AIF, with $75/acre added for undeveloped land, less long-term debt and existing asset liabilities. Includes value of midstream assets. See reserves disclosures on pages 14 to 17.

Years ended December 31	**2003**	2002	2001	2000	1999	1998	1997	1996	1995	1994
OPERATING INFORMATION										
Crude oil and NGLs (mmbbl)										
Proved reserves, before royalties										
North America	**672**	665	644	643	554	284	257	136	51	41
North Sea	**222**	203	83	102	–	–	–	–	–	–
Offshore West Africa	**106**	94	61	36	–	–	–	–	–	–
	1,000	962	788	781	554	284	257	136	51	41
Proved and probable reserves, before royalties										
North America	**977**	742	740	731	640	380	329	185	74	55
North Sea	**317**	277	106	134	–	–	–	–	–	–
Offshore West Africa	**187**	162	111	46	–	–	–	–	–	–
	1,481	1,181	957	911	640	380	329	185	74	55
Natural gas (bcf)										
Proved reserves, before royalties										
North America	**3,006**	3,048	2,566	2,360	2,183	1,901	1,716	1,566	908	874
North Sea	**62**	71	94	91	–	–	–	–	–	–
Offshore West Africa	**86**	90	69	65	–	–	–	–	–	–
	3,154	3,209	2,729	2,516	2,183	1,901	1,716	1,566	908	874
Proved and probable reserves, before royalties										
North America	**3,611**	3,450	2,915	2,762	2,547	2,211	2,078	1,926	1,111	1,044
North Sea	**101**	89	118	114	–	–	–	–	–	–
Offshore West Africa	**111**	120	96	84	–	–	–	–	–	–
	3,823	3,659	3,129	2,960	2,547	2,211	2,078	1,926	1,111	1,044
Total proved reserves, before royalties (mmboe)	**1,526**	1,497	1,243	1,200	918	601	543	397	202	187
Total proved and probable reserves, before royalties (mmboe)	**2,118**	1,791	1,479	1,404	1,065	749	675	506	259	229
Daily production, before royalties										
Crude oil and NGLs (mbbl/d)										
North America	**175**	169	167	155	87	76	71	37	17	13
North Sea	**57**	39	36	17	–	–	–	–	–	–
Offshore West Africa	**10**	7	3	2	–	–	–	–	–	–
	242	215	206	174	87	76	71	37	17	13
Natural gas (mmcf/d)										
North America	**1,245**	1,204	906	793	721	673	626	499	305	238
North Sea	**46**	27	12	1	–	–	–	–	–	–
Offshore West Africa	**8**	1	–	–	–	–	–	–	–	–
	1,299	1,232	918	794	721	673	626	499	305	238
Total production, before royalties (mboe/d)	**459**	421	359	306	207	188	175	120	68	53
Product pricing										
Average crude oil and NGLs price ($/bbl)	**31.59**	29.76	24.31	29.99	21.04	12.93	18.82	23.52	19.82	18.18
Average natural gas price ($/mcf)	**6.02**	3.76	5.16	4.53	2.36	2.12	1.91	1.71	1.43	1.99

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(1) Defined as Unrelated under the Corporate Governance Guidelines issued by the Toronto Stock Exchange; and defined as Independent under the United States Sarbanes-Oxley Act of 2002, and the listing standards of the New York Stock Exchange.

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Printed in Canada by Sundog Printing

Principal photography by Gary Campbell
Additional photography by Canadian Natural team members
Oilsands mine photos, courtesy of Albian's Muskeg River Mine

designed and produced by nonfiction studios inc.

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Important Dates

INTERIM REPORT FIRST QUARTER 2004
Wednesday, May 5, 2004

ANNUAL AND SPECIAL MEETING OF THE SHAREHOLDERS
Thursday, May 6, 2004

INTERIM REPORT SECOND QUARTER 2004
Wednesday, August 4, 2004

INTERIM REPORT THIRD QUARTER 2004
Wednesday, November 3, 2004

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